2012 Integrated Resource Plan for Connecticut

Prepared by:

The Connecticut Department of Energy and Environmental Protection

June 14, 2012

Connecticut Department of
ENERGY &
ENVIRONMENTAL
PROTECTION

June 14, 2012

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Environment Committee
Room 3200 Legislative Office Building
Hartford, CT 06106

Re: Report to the General Assembly Regarding the 2012 Integrated Resource Plan pursuant to section 16a-3a of the General Statutes of Connecticut and as amended by Public Act 11-80.

Dear Chairs and Ranking Members:

In compliance with the requirements of section 16a-3a of the 2012 Supplement to the General Statutes of Connecticut and as amended by sections 89 and 90 of Public Act 11-80, <u>An Act Concerning the Establishment of the Department of Energy and Environmental Protection and Planning for Connecticut's Energy Future,</u> the Department of Energy and Environmental Protection (DEEP) submits the 2012 Integrated Resource Plan (IRP).

DEEP is pleased to present this 2012 IRP as part of its mission to develop and implement energy resource strategies that will ensure that electricity in Connecticut is affordable, clean, and reliable. The 2012 IRP reflects the hard work of many people throughout the Department and the valuable input of the Connecticut Energy Advisory Board, the electric distribution companies, the Office of Consumer Counsel, and many stakeholders.

The 2012 IRP provides an in-depth assessment of the state's energy and capacity resources. It then sets forth a plan for meeting projected demand and lowering the cost of electricity by utilizing a mix of generating facilities and efficiency programs. The IRP presents numerous opportunities to continue to improve Connecticut's energy profile, and provides strategies to meet the needs of end-users in a cost effective manner, while maximizing consumer benefits and advancing the state's environmental goals and standards.

If you have any questions regarding the enclosed report please contact me or my legislative liaison, Robert LaFrance, at 860-424-3401.

Sincerely,

Daniel C. Esty
Commissioner

cc: State Librarian, Office of Legislative Research, Clerks of the House & Senate

Pursuant to Connecticut General Statutes section 16a-3a, I hereby approve this "2012 Integrated Resources Plan for Connecticut." The effective date of this 2012 Integrated Resources Plan shall be June 14, 2012.

Daniel C. Esty
Commissioner
Department of Energy and Environmental Protection

Approved: June 14, 2012

EXECUTIVE SUMMARY

The 2012 Integrated Resource Plan (IRP) for Connecticut presents a comprehensive plan for improving Connecticut's electric energy future. The 2012 IRP is the fourth for Connecticut and the first developed by the Department of Energy and Environmental Protection (DEEP), pursuant to section 16-3a of the Connecticut General Statutes. Based on analyses of projected future electricity supply and demand, the 2012 IRP outlines a plan for securing resources to meet the state's energy needs in a way that will minimize the cost to Connecticut customers over time and maximize consumer benefits consistent with the state's environmental goals and standards. The strategies identified in the IRP will help to make electricity cheaper, cleaner, and more reliable, while supporting in-state employment.

Forecast for Future Electricity Supply and Demand

- **Connecticut's electricity consumption declined sharply during the economic recession, and is not expected to exceed 2005 levels until 2022.** Over the next several years, consumption is expected to grow at approximately 1% per year. Slightly higher growth rates are expected for the annual peak load (the electricity demanded during the hour with the highest total demand).

- **Adequate generating resources will likely be available in Connecticut to serve electricity loads reliably through 2022.** New England as a whole also will have adequate resources and likely not need new generation until 2022, though depending on market conditions new generation could be needed as early as 2018. These findings are based on reasonable assumptions about market conditions, the completion of planned transmission projects, and generation retirements that are likely to occur given compliance with stricter rules for air emissions being promulgated by the U.S. Environmental Protection Agency (EPA).

- **The deliverability of natural gas fuel to electric generators requires monitoring to assure the reliability of electricity supply.** The regional power supply has become quite dependent on natural gas-fired generation, but most of those generators rely on "as-available" non-firm pipeline capacity for natural gas delivery. The amount of non-natural gas capacity plus natural gas-fired capacity currently identified as having either firm pipeline capacity or dual-fuel capability appears to be sufficient to meet winter electric demand (when competing space-heating demands for natural gas are greatest), but additional verification of back-up fuel supplies and analysis of wintertime operational challenges may be necessary to assure continued reliability.

- **Connecticut is beginning to experience lower Generation Service Charges, and can expect the downward trend to continue over the next five years.** After several years of Generation Service Charges being 10-12 ¢/kWh, those charges should now remain at or below 8 ¢/kWh through 2017 (in constant 2012 dollars) due to moderate wholesale natural gas and power prices caused by expanding shale gas supplies.

- **Between 2017 and 2022, Generation Service Charges are projected to rise by more than 3 ¢/kWh in real terms**, due to a combination of rising capacity prices (due to region-wide demand growth), rising energy prices (mostly due to expected natural gas price increases), rising Class 1 Renewable Portfolio Standards (RPS) targets and higher renewable energy credit prices (due to anticipated scarcity). Rates in 2022 could turn out to be higher or lower depending on market conditions, but are still expected to increase from projected 2017 levels.

- **Air pollution emissions in Connecticut have decreased, as low-cost natural gas-fired generation is displacing coal and oil-fired generation.** 2010 emissions of NOx, SO_2, and CO_2, fell 36%, 70%, and 10%, respectively, from 2007 levels, and they are projected to fall another 49%, 45%, and 12% by 2015. New England emissions likewise will fall from 2010 levels until 2015. Thereafter, emissions in New England and Connecticut will rise very slowly as electricity demand grows, but remain below 2010 levels through 2022.

- **A gap between projected available renewable generation and demand mandated by Connecticut's and other New England states' renewable generation targets is expected to emerge in 2018.** Connecticut has the highest target for renewable generation (20% by 2020) of all New England states, but few native resources apart from a set of in-state projects that depend on special state-sponsored contracts. Connecticut load-serving entities satisfy these renewable requirements mostly by purchasing renewable energy credits generated elsewhere in New England, competing with other states in a regional renewable energy credit market. Unless regional development of renewable resources and enabling transmission accelerates, Connecticut customers could face Alternative Compliance Payment obligations of more than $250 million (in 2012 dollars) annually by 2022. Addressing this potential burden represents an important policy priority.

Plan for Achieving Cheaper, Cleaner, More Reliable Energy Sources

The downward rate trend for the next five years provides policy makers an opportunity to put into place long-term policy measures that will alleviate expected rate increases from 2017 to 2022. The 2012 IRP identifies a plan consisting of several resource strategies that will help customers reduce the volume of consumption and, thus, save money when market-wide cost factors pressure rates; facilitate the development of low-cost, clean energy resources that are economic but may face barriers to implementation; find cost-effective ways to meet the clean energy objectives of the renewable targets; and support in-state jobs. Those strategies are as follows:

1. **Expand Energy Efficiency to Attain All Cost-Effective Energy Savings**. Based on the 2010 study of Connecticut's energy efficiency potential commissioned by the state's Energy Conservation Management Board (now the Energy Efficiency Board), the IRP concludes that the state can cost-effectively achieve approximately 2% energy savings each year, reducing energy consumption by 0.4% per year on net if the economy grows as expected. These savings can be achieved by increasing the budget for

Conservation and Load Management (C&LM) programs from $105 million annually under a business-as-usual budget to $206 million annually, and by initiating complementary measures such as providing low-cost financing, implementing more aggressive codes and standards, and motivating behavioral changes through information and training.

Net of all program and participant costs, customers would save $534 million per year by 2022 compared to a business-as-usual base case. The savings arise from reduced consumption of energy, capacity, and renewable credits, and also from reductions in market prices resulting from expanding this low-cost resource. The expanded efficiency programs and associated customer savings would support an additional 5,500 in-state jobs by 2022; cause projected air emissions to decline between 5% and 10%; and help make Connecticut a national leader in innovative approaches to achieving cost-effective energy efficiency.

2. **Analyze Renewable Portfolio Standard Issues and Develop Longer Term Renewable Energy Policy.** In accordance with Section 129 of Public Act 11-80, DEEP will prepare an analysis of RPS issues, including progress in reaching the targets and options for minimizing cost to ratepayers, and develop a longer-term renewable energy policy over the next six months. Careful monitoring of the overall progress will be important to ensure that efforts to meet the Class I Renewable Portfolio Standards do not unnecessarily increase customer costs.

   As part of this analysis, DEEP will evaluate potential policy revisions to restore incentives for combined heat and power resources and remove utility-based energy efficiency programs from Class III qualification. Since utility-based energy efficiency programs are funded through the Conservation and Load Management program, the Class III Renewable Portfolio Standard should be revised to focus primarily on providing incentives to combined heat and power and third-party energy efficiency programs that do not have a dedicated source of funding.

   DEEP will also analyze whether the RPS provides sufficient incentives for Class II generators, or if other options such as purchase power arrangements are necessary to ensure the continued operation of in-state resource recovery facilities. Over the past few years energy revenues have declined significantly creating hardship for some in-state resource recovery facilities. In addition, Class II REC prices are low and RECs may go unsold due to an over-supply. DEEP believes it is critical to examine the issues facing in resource recovery facilities to develop a long-term plan to put them in a position to continue operations on a competitive basis.

3. **Pursue Existing Opportunities to Maximize Cost-Effective Renewables.** DEEP will continue to work with other New England states (through the New England State Committee on Electricity process) to define the most cost-effective means to expand renewable energy development in the region. Connecticut's renewable energy percentage targets may be met by planning

and developing cost-effective transmission to interconnect and integrate regional renewable resources, and by maximizing the use of cost-effective in-state resources. DEEP supports efforts to drive down the cost of technologies that can best be deployed within Connecticut, such as solar photo voltaic systems and fuel cells. In addition, DEEP supports removing barriers and considering options to maximize the development of other in-state renewable energy resources. Moving forward, if cost-effective renewable resources and associated transmission projects do not sufficiently develop in New England, or if customers pay large amounts of Alternative Compliance Payments without achieving the Renewable Portfolio Standard objectives, then DEEP would consider other methods to reduce air emissions from the power sector by further increasing the investments in other clean energy or efficiency resources.

In addition to these long-term resource strategies, DEEP will continue to examine critical reliability issues and to collaborate with regional entities on solving them. These activities will include:

4. **Periodically Review Adequacy of Local Resource Supplies for Providing Reliable Generation Service during Peak Demand Periods.** Although the IRP identified no likely resource need in the near-term, DEEP will continue to monitor resource supplies, including the retirement of existing generation, the effect of energy efficiency on electricity demand, and the progress of the NEEWS transmission project. DEEP will also work with ISO-NE to ensure that its market structures provide proper incentives to retain and develop new resources when and where needed.
5. **Maintain Reliability During Winter Cold Snaps.** DEEP will work with ISO-NE to maintain reliability during winter cold snaps, when natural gas availability for generation is lowest. To ensure preparedness with backup fuels, PURA should assess the compliance of Connecticut generators with their siting requirements and contractual obligations regarding fuel capabilities.
6. **Facilitate Deployment and Funding of Microgrid and Smart Grid Technology.** Pursuant to Governor Malloy's Two Storm Panel Review and ongoing efforts for Connecticut to address storm disaster preparedness and recovery, DEEP will undertake a pilot program for the deployment and funding of distributed generation and microgrids, combined with smart grid technology at critical facilities (such as hospitals, prisons, and sewage treatment plants) and in city centers, as well as the use of energy improvement districts as a mechanism to support microgrids.

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2012 INTEGRATED RESOURCE PLAN FOR CONNECTICUT

I. INTRODUCTION

A. Purpose

The 2012 Integrated Resource Plan (IRP) for Connecticut presents a comprehensive plan for improving Connecticut's electric energy future. The 2012 IRP is the fourth for Connecticut and the first developed by the Department of Energy and Environmental Protection (DEEP), pursuant to section 16-3a of the Connecticut General Statutes. Based on analyses of projected future electricity supply and demand, the 2012 IRP outlines a plan for securing energy resources that will minimize the cost to Connecticut customers over time and maximize consumer benefits consistent with the state's environmental goals and standards. The strategies identified in the IRP will help to make electricity cheaper, cleaner, and more reliable, while supporting in-state employment.

B. Statutory Authority

Pursuant to section 16a-3a of the 2012 Supplement to the General Statutes of Connecticut and as amended by sections 89 and 90 of Public Act 11-80, <u>An Act Concerning the Establishment of the Department of Energy and Environmental Protection and Planning for Connecticut's Energy Future</u> (Act), the Commissioner of the Department of Energy and Environmental Protection (DEEP) is charged with reviewing the state's energy and capacity resource assessment every two years, and developing an Integrated Resource Plan that identifies how best to meet projected demand and lower the cost of electricity, utilizing a mix of generating facilities and efficiency programs while minimizing costs to customers, maximizing consumer benefits, and advancing the state's environmental goals and standards.[1] The resource needs identified in the IRP must first be met through all available cost-effective conservation and load management measures.[2]

In accordance with the Act, the Department, in consultation with the Connecticut Energy Advisory Board and the electric distribution companies, developed the 2012 IRP to assesses: (1) the state's energy and capacity resource outlook for the next three, five, and ten years; (2) the manner of how best to eliminate growth in electric demand; (3) how best to level electric demand in the state by reducing peak demand and shifting demand to off-peak periods; (4) the impact of current and projected environmental standards, including but not limited to, those related to greenhouse gas emissions and the federal Clean Air Act goals and how different resources could help achieve those standards; (5) energy security and economic risks associated with potential energy resources; and (6) the estimated lifetime cost and availability of potential energy resources. The 2012 IRP articulates a vision contemplated in the Act for improving Connecticut's energy future, and identifies a set of resource strategies that together will ensure that electricity in Connecticut is affordable, clean, and reliable.

[1] *See* 2012 Supplement to the General Statutes of Connecticut, Section 16a-3a(a).
[2] *Id.* at § 16a-3a(c).

Additionally, in developing the IRP, the Department has addressed policies and plans that are governed by other statutory mandates. The Department is required under Section 33(d)(1) of the Act to approve, modify or reject any comprehensive Conservation and Load Management (C&LM) plan submitted by the Energy Efficiency Board (EEB) under that section. The 2012 C&LM Plan submitted by the EEB recommended an ambitious expansion of the C&LM programs that incorporates additional investment in, and savings from, programs related to electricity, natural gas, and fuel oil. In a December 23, 2011 Notice of Request for Comments and Technical Meeting, the Department stated that as part of its implementation of Section 33(d)(1) of the Act, it will consider the expanded electric program within the context of the IRP.

The IRP also addresses in part the requirements of Section 129 of the Act, which directs the Department to analyze options for minimizing the cost to ratepayers of procuring renewable resources, and the feasibility of increasing the renewable energy portfolio standards (including consideration of expanding the definition of Class I renewable energy sources to include hydropower and other technologies that do not use nuclear or fossil fuels). As relevant to the Section 129 requirement, the 2012 IRP includes an analysis of alternative energy scenarios for the years 2012-2022, that model the annual percentage of renewable resources in a way that will reduce ratepayer costs, increase environmental benefits, and improve the state's economic activity. In the coming months, the Department expects to further evaluate the options for modifying the renewable energy portfolio standards in order to minimize the cost of renewable resource procurement and maximize its benefit to the state's economy.

As shown in Appendix B, Resource Adequacy, the Department evaluated the total amount of energy and capacity resources needed for customer requirements, the extent to which C&LM activity can cost-effectively meet these needs on an equitable basis, and whether new generation, transmission, and distribution improvements are needed.

C. Procedural Development of the 2012 IRP

The Department developed the 2012 IRP with analytical assistance from The Brattle Group, an economic consulting firm. DEEP staff met regularly with subject area experts from other state agencies, the EDCs, natural gas distribution companies, and The Brattle Group, to address issues related to resource adequacy and electricity market modeling, energy efficiency, renewables, natural gas, environmental issues, transmission, emerging technology, and macroeconomic analysis.

On September 19, 20, and 22, 2011, the Department conducted a series of meetings to obtain stakeholder feedback on the scope of the IRP during the development of the draft. A total of 14 presentations were given over the three-day period covering major topic areas including: Energy Efficiency, Renewables, Natural Gas, Transmission, Environmental and Emerging Technologies. Presenters included DEEP staff, the Connecticut Energy Efficiency Board, Celtic Energy, Lantern Energy, ISO-NE, Tennessee Gas Pipeline, Iroquois Gas Transmission Systems, Environmental Energy Solutions, Connecticut Energy Advisory Board, Quantum Utility Generation, Alteris Renewables, Connecticut Center for Advanced Technology, Inc. and New England States Committee on Electricity. Subsequent to the initial stakeholder meetings, written comments were submitted by Environment Northeast (ENE), New England Power Generators Association, Inc. (NEPGA), Kimberley-Clark Corporation, and NRG Energy, Inc (NRG).

A draft of the IRP was issued by the Department on January 20, 2012, together with a notice inviting written comments over a 45-day period. The Department conducted a technical meeting on February 1, 2012 at its offices at Ten Franklin Square, New Britain, Connecticut, to present the 2012 draft IRP and receive public comment. The technical meeting continued on Wednesday, February 1, 2012, at 1:00 p.m. dedicated to the expanded electric C&LM program proposed in the draft IRP. On March 2, 2012, DEEP conducted a public hearing in accordance with the requirements of Chapter 54 of the General Statutes of Connecticut, to enable the public to comment on the draft IRP and the expanded electric C&LM program. Written comments submitted on the 2012 IRP, and recordings of the February 1 and March 2, 2012 technical meeting are all available on the DEEP website.[3]

The Department received 28 written comments on the draft IRP, representing the views of the following entities: Woodlands Coalition, Environmental Energy Solutions (EES), Sierra Club, Connecticut Fund for the Environment (CFE), AARP Connecticut, Clean Water Action, Connecticut Industrial Energy Consumers (CIEC), Connecticut Business and Industrial Association (CBIA), Connecticut Energy and Advisory Board (CEAB), the Connecticut Light & Power Company/Yankee Gas (CL&P), Class III CHP Organization, Eastern Connecticut State University (ECSU), CPV Towantic, LLC, Connecticut Siting Council (CSC), ENE, Northeast Energy Efficiency Partnerships (NEEP), NEPGA, the Office of Consumer Counsel (OCC), the United Illuminating Company (UI), NRG, United Technologies Corporation Power (UTC Power), Renewable Energy New England (RENEW) and the Conservation Law Foundation, Clearedge Power, Inc., Coalition for Renewable Natural Gas, Inc., Constellation Energy Commodities Group, Inc. and Constellation NewEnergy, Inc. (CNE), Naugatuck Energy Development, LLC and a letter from concerned citizens signed by approximately 500 Connecticut residents.

The written comments focused on four key issues: the expanded savings scenario proposed by the EDCs and EEB in the C&LM Plan; the need for flexibility in regard to the states renewable portfolio standard (RPS) requirements; transmission; the need for increased generation, including combined heat and power (CHP), and repowering of certain generation assets. Some comments also addressed the forecast assumptions used in IRP. A summary of the comments and the Department's responses thereto are attached herein as Appendix J.

II. THE ELECTRICITY SECTOR AND THE SCOPE OF THE 2012 IRP

The purpose of the IRP is to identify resource strategies that can be implemented by the State to make electricity cheaper, cleaner, and more reliable. To that end, it is it is critical to recognize the kinds of resource strategies that are within the state's jurisdictional control, within the current regulatory and market context.

With the restructuring of Connecticut's electricity sector in 1998, the state does not directly determine how electricity is generated or transmitted, and it does not set prices charged for generation or transmission services. Electricity is generated by independent power producers and sold to customers via the electric distribution companies (EDCs) or competitive retail

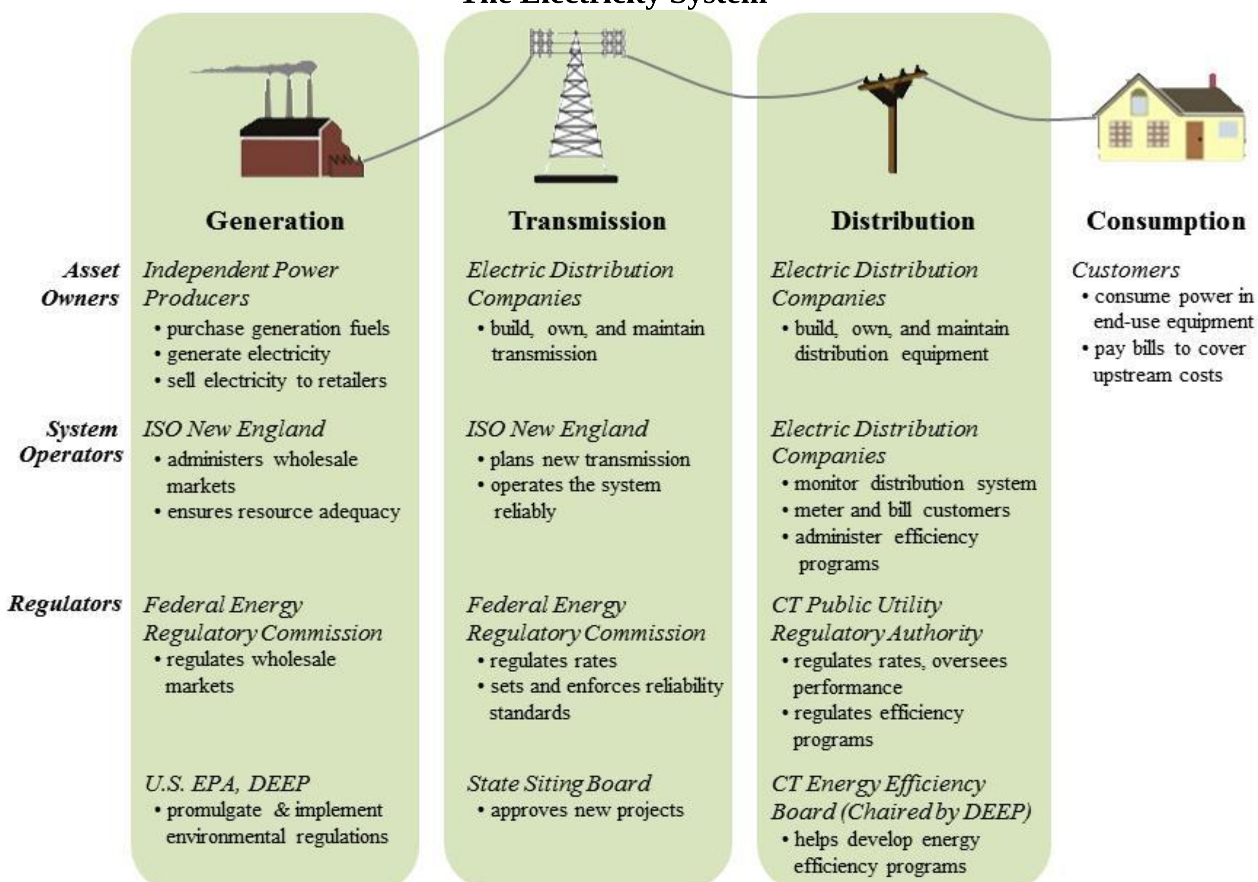
[3] Written comments and technical meeting recording are available at http://www.dpuc.state.ct.us/DEEPEnergy.nsf/$EnergyView?OpenForm&Start=1&Count=30&Expand=2.3&Seq=4.

providers at market-based prices. The wholesale market and the transmission system are administered by the New England Independent System Operator (ISO-NE) and regulated by the Federal Energy Regulatory Commission (FERC). Together, ISO-NE and FERC provide for open transmission access so that the lowest-cost available resources can be utilized (subject to transmission constraints), and ensure that market price outcomes are competitive.

The state's role focuses on overseeing energy efficiency programs, regulating the distribution system, implementing environmental policies, setting renewable targets on the types of supply purchased by retailers, occasionally soliciting contracts for particular generation resources on behalf of all customers, and engaging with ISO-NE in the development of market rules and in transmission planning processes.

Figure 1 shows a picture of the electricity system and describes the primary players that influence each component of the system: from generation to transmission to distribution to the customer. In addition to the entities depicted, there are many influential secondary players not included in the figure, such as lenders, energy traders, energy service companies, and curtailment service providers (who help customers manage their peak loads and sell load reductions as supply into the wholesale markets).

Figure 1
The Electricity System



Each of the parties identified in Figure 1 contribute in different ways to the cost, environmental impacts, and reliability (*i.e.*, resource adequacy, transmission security, and distribution resiliency) of the electricity system. Generation accounts for the largest (and most variable) portion of rates, and produces all of the emissions.[4] Market-based generation rates reflect wholesale market prices, which are largely driven by natural gas prices, regional supply-demand fundamentals, and market rules. Figure 2 describes these contributions.

Figure 2
Costs, Reliability, and Environmental Impacts of Electricity

	Generation	Transmission	Distribution
Costs/Rates			
Determinants	*Wholesale Market Conditions* • gas prices • supply-demand fundamentals *Special contract costs*	*Embedded Costs* • historic capital expenditures • cost allocation *Going Forward Costs* • new investment • operations & maintenance	*Embedded Costs* • historic capital expenditures *Going Forward Costs* • new investment • operations & maintenance
Approximate Current Rates	*9.5 ¢/kWh (varies)*	*1.8 ¢/kWh*	*5.0 ¢/kWh*
Reliability			
Criteria	*Resource Adequacy* • enough resources to meet peak loads and prevent shedding firm load more than once in ten years, with margin for forecast uncertainty and outages	*Transmission Security* • protect individual facilities and maintain the voltage and stability of the system in the face of contingencies	*Distribution Resiliency* • deliver customer power under all load conditions • storm preparedness and response
Who Enforces	*ISO New England*	*ISO New England*	*CT Public Utility Regulatory Authority*
Environment	*Air* • NOx, SOx, CO2, particulates, mercury, other *Water* • cooling water intake, discharge	*Land Use Impacts*	*Aesthetics* • overhead lines vs. underground • tree trimming

Energy efficiency programs, not shown in Figure 2, have been funded for many years primarily through a 0.3 ¢/kWh "systems benefits charge" on all customers' bills. These programs and other state policies have been ranked by the American Council for an Energy Efficient Economy (ACEEE) as the 8th best in the country, indicating success with room for improvement.

The 2012 IRP focuses primarily on resource strategies that can be implemented by the State to make electricity cheaper, cleaner, and more reliable. To that end, the IRP focuses on the state-jurisdictional areas identified above, particularly on the subset of areas that involve potential resource investments. It excludes a few important areas of state jurisdiction because they are being addressed concurrently outside of the IRP. For example, distribution resiliency and storm response are excluded because they have been the subject of investigation by the Governor's office. The procurement of wholesale power to serve customers who choose to buy generation

[4] Approximate rates shown are representative for a typical residential customer in Connecticut in 2012. The "Generation" rate includes the Generation Service Charge and charges for special contracts.

from the EDCs is also excluded because it is being addressed by Connecticut's new procurement manager in accordance with his or her authorities prescribed under the Act.

III. ANALYTICAL APPROACH

The analytical approach used to develop the 2012 IRP included the following four sequential steps:

1. Develop Base Case assumptions and a three, five, and ten-year outlook for resource needs in Connecticut and New England; certain aspects of reliability; customer rates; and emissions. Analyze the drivers of likely changes in Connecticut customer rates as a starting point for identifying improvement opportunities.

2. Analyze how outcomes could change under alternative Futures regarding market conditions the state cannot directly control, including natural gas prices, broad economic growth, and generation supply.

3. Evaluate several Resource Scenarios and policy options the state could pursue involving energy efficiency, renewable generation (including remote resources and associated transmission), and new conventional generation, to reduce costs and emissions while supporting in-state jobs. Test the robustness of Resource Scenarios against the Base Case and alternative futures. Consider ways to enable emerging technologies that may be part of a longer-term solution.

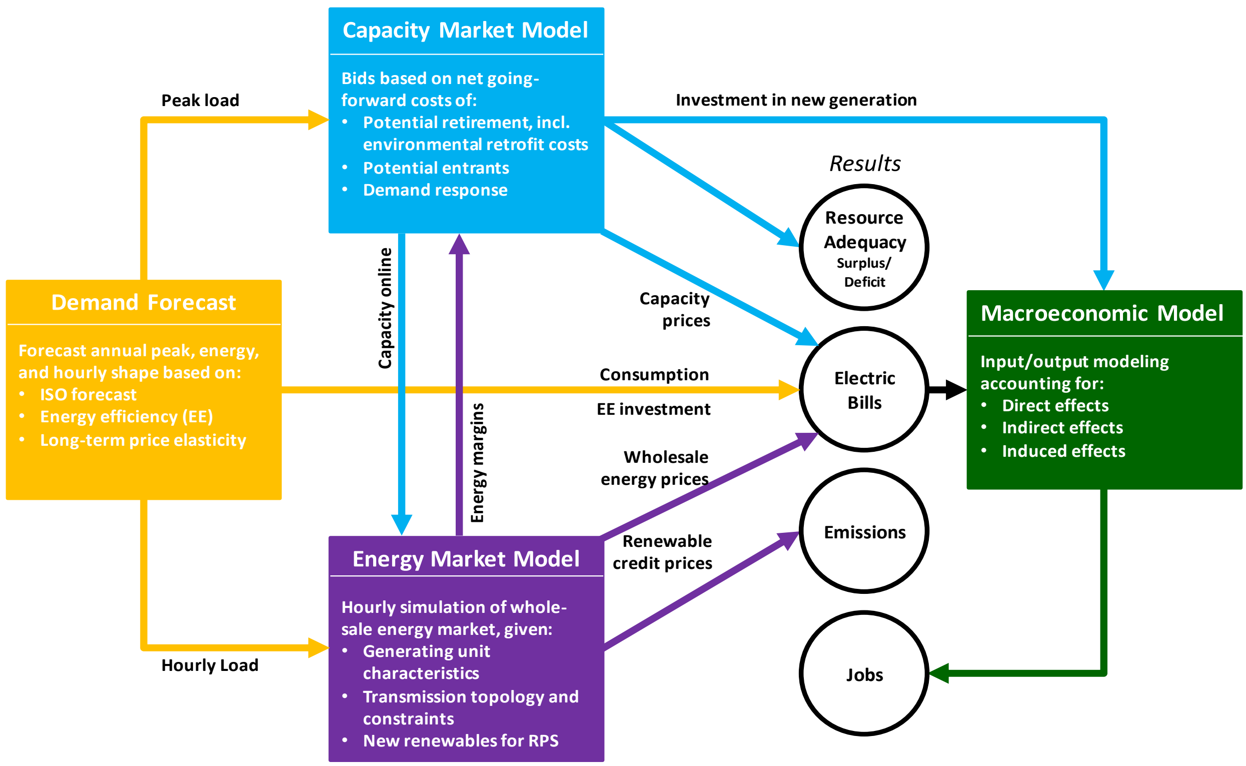
4. Develop a plan, based on the findings above.

The findings and analyses prepared in each step in the sequence are provided in Sections IV through VII of the 2012 IRP. These analyses are based on publicly available data about the Connecticut and broader New England electricity markets. Projections and impact analysis also rely on a modeling system with four major interconnected components, as depicted in Figure 3. These components include: a demand forecast; a capacity model used to simulate capacity prices in ISO-NE's Forward Capacity Market and to project new resource entry and retirement decisions; the DAYZER[5] model used to simulate ISO-NE's energy market, generator operations, and locational marginal prices (LMPs) in Connecticut, with a closely-linked renewables model to project renewable energy credit (REC) prices; and a macroeconomic model (REMI) used to analyze impacts on in-state jobs. The electricity models were developed and utilized in prior IRPs and were employed again by The Brattle Group under the Department's direction. The REMI analysis was prepared by the Connecticut Department of Economic & Community Development.

Complementing the modeling system, the Department directed extensive research and analysis of publicly available information on resource adequacy, energy efficiency, renewables, natural gas, environmental issues, transmission, and emerging technology. Detailed explanations of the various components of the analysis are provided in Appendices A through I. All dollar figures in this report are presented in 2012 dollars except where noted otherwise.

5 DAYZER is a commercially available model developed by Cambridge Energy Solutions.

Figure 3. Schematic of the Modeling System



IV. BASE CASE TEN-YEAR OUTLOOK

A. Supply and Demand for Capacity

Because electricity cannot be stored in meaningful quantities, the electricity sector must maintain an intentional surplus of resources to be able to serve customer demand every hour. This surplus must be sufficient to serve customers even under extreme conditions, such as on the hottest summer days when demand for electricity spikes and generating units unexpectedly break down. Resources can be supplied in many different ways, including generating capacity, transmitting power from other regions, and predictably curtailing demand when needed. Various metrics are used to measure resource adequacy and to quantify expected reliability.

The base case Ten-Year outlook analyzed in this section projects that the supply of capacity resources is greater than needed to meet peak electricity load reliably over the next decade.[6]

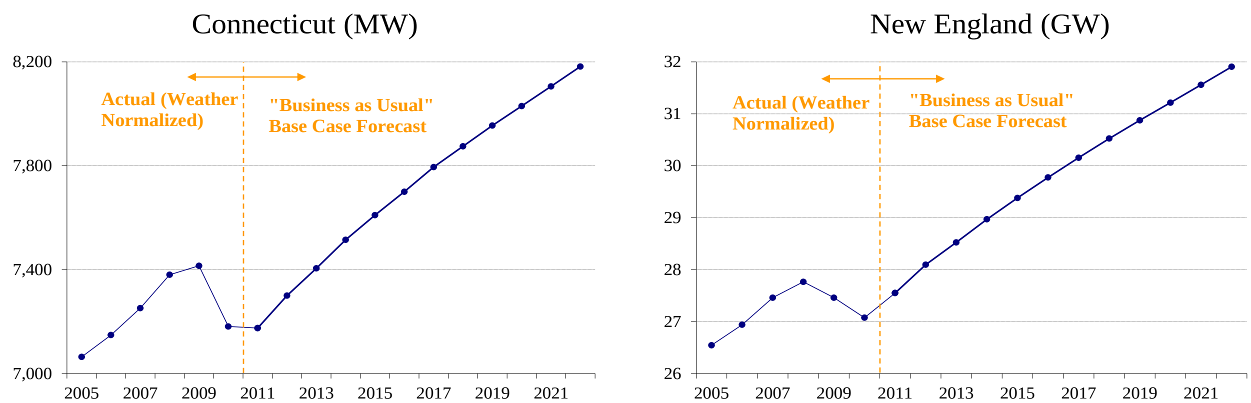
[6] "Peak load" refers to the maximum amount of power (measured in megawatts) used by customers over the course of a year. In New England, the peak load hour usually occurs during July or August. In general, "MW" refers to capacity, or power, while "megawatt-hours" (MWh) refer to energy produced or consumed. One MWh is equal to a MW of power produced or consumed over one hour. Common prefixes for both Watt and Watt-hour measures include "kilo" (k = 1,000), "mega" (M = 1,000,000), "giga" (G = 1,000,000,000) and "tera" (T = 1,000,000,000,000).

That is, resource adequacy requirements set by ISO-NE are projected to be satisfied for ten years in both the Connecticut sub-area and in the New England region as a whole. This projection is attributable to several factors: (1) the region has an existing capacity surplus of more than five thousand megawatts; (2) demand growth is forecasted to be slow, partly due to the current economic conditions and partly because of continued utility energy efficiency programs and new codes and standards; (3) new transmission into Connecticut is helping to meet local adequacy requirements; and (4) the current capacity surplus is large enough to withstand the effect of likely generation retirements resulting from the implementation of EPA's proposed Air Toxics rule in 2015-2016 and the planned elimination of the capacity price floor in 2017-2018.[7] Thus, additional generating resources will not be needed for resource adequacy purposes. New generating resources may be needed, however, to serve other policy objectives, including reducing costs and emissions and supporting in-state jobs. These scenarios are discussed in later sections of the 2012 IRP.

Peak Load Forecast

Peak load in Connecticut declined during the recent economic recession, as demonstrated in Figure 4. ISO-NE forecasts an annual growth rate of 1.7% (125 MW/year) over the next few years, decreasing to 0.9% (75 MW/year) by 2020. The New England system peak load is forecast to grow at an annual rate of 2.0% initially (545 MW/year), decreasing to 1.1% growth (340 MW/year) by 2020, as shown in Figure 4.[8] These peak load projections do not deduct the effects of energy efficiency, most of which is counted separately as a supply-side resource in ISO-NE's Forward Capacity Market and in the supply-demand projections in the 2012 IRP.[9]

Figure 4
Peak Load — Historical and Forecast



7 These and related factors are described in more detail below and in Appendix B (Resource Adequacy).

8 The Connecticut 2010 peak value is a Brattle Group estimate based on data from ISO-NE.

9 These are ISO-NE's "gross" forecasts, before accounting for demand-side resources that have cleared in forward capacity auctions. However, as discussed in Appendix B (Resource Adequacy), these forecasts do implicitly include some level of business-as-usual efficiency improvement.

Connecticut and New England Reliability Requirements

ISO-NE has established several resource adequacy requirements that affect Connecticut.

- **Connecticut Local Sourcing Requirement.** ISO-NE defines two requirements for local capacity in Connecticut: the Local Resource Adequacy requirement and the Connecticut requirement under the Transmission Security Analysis.[10] Whichever requirement is more stringent determines the local requirement. Because the capacity required under the Transmission Security Analysis has historically been greater than the capacity required under the Local Resource Adequacy requirement, the 2012 IRP's resource adequacy analysis focuses on that measure.
- **Net Installed Capacity Requirement (NICR) for the New England region.** The Net Installed Capacity Requirement is the total amount of capacity needed to achieve the applicable reliability target specified in ISO-NE's Planning Procedures (and by the North American Electric Reliability Corporation) to limit the probability of disconnecting non-interruptible customers due to resource deficiency to no more than once in ten years. The Net Installed Capacity Requirement also sets the total demand for capacity in ISO-NE's forward capacity auctions. Notably, ISO-NE has recently changed the methodology for determining the requirement, which has increased the Net Installed Capacity Requirement from 11.4% above forecast peak load to 14.4% above peak. This change represents an increase of approximately 1,000 MW. This higher required reserve margin will tend to increase capacity costs and reduce energy costs.
- **Connecticut Locational Forward Reserve Market Requirement**. This requirement ensures enough quick-start capacity within Connecticut to recover from a second contingency occurring in Connecticut. Commonly, the second contingency protection for this market requirement is an unexpected outage of the Millstone 3 nuclear unit.

Existing, Planned, and Assumed Future Resources

To analyze compliance with the Net Installed Capacity Requirement and Connecticut reliability requirements, the Department first considered "known" generating and demand-side resources, i.e., those that already exist or new resources expected to be online, based on currently available information:

- *Existing Generating Capacity.* As of January 1, 2011, there are 8,150 MW available in the Connecticut sub-area and 32,027 MW available region-wide to meet reliability requirements.[11]
- *Planned Additions*. Planned additions fall into two categories: capacity built to help satisfy Renewable Portfolio Standards (RPS) and capacity built for

[10] See http://www.iso-ne.com/genrtion_resrcs/reports/nepool_oc_review/2011/ icr_2014_2015_final_report.pdf

[11] Capacity online is documented in the ISO-NE "2011-2020 Forecast Report of Capacity, Energy, Loads and Transmission" (2011 CELT Report).

other reasons. The latter, non-RPS Planned Additions include the 130 MW New Haven Harbor gas turbine plant scheduled to come online on June 1, 2012 and an 88 MW expansion to Northfield Mountain pump-storage plant in Massachusetts scheduled to be completed by Summer 2015. Planned additions to satisfy RPS requirements are 46 MW (46 MW capacity value) in Connecticut and 170 MW (69 MW capacity value) region-wide.[12] These include projects being developed for Project 150 in Connecticut as well as additional onshore wind and solar PV that are currently being developed or have announced plans to build. In addition, the Department assumes 343 MW (150 MW capacity value) of renewables that are not yet planned will be developed in Connecticut and 2,470 MW (766 MW capacity value) region-wide to help meet RPS requirements, as discussed in the "Outlook for Renewable Generation Supply and Demand" section below.

- *Retirements*. Based on publicly available information and third-party data, the Department assumes the retirement of 183 MW in Connecticut (AES Thames) and 1,366 MW in the rest of New England (Salem Harbor, Vermont Yankee, Holyoke 8/Cabot 8, and Holyoke 6/Cabot 6). Additional economic retirements are discussed below.
- *Demand Resources*. Demand resources include active demand response, and passive demand response. "Active demand response" is the ability to reduce participating customers' loads when called upon by ISO-NE if committed generating resources are insufficient to meet the peak demands. Curtailment service providers sell these so-called active demand response "negawatts" into the forward capacity auctions. "Passive demand response" primarily covers energy efficiency. Both active and passive demand response resources are treated as supply resources in the Forward Capacity Market. For the 2012 IRP analysis, the Department counted all demand response resources committed in the forward capacity auction for delivery year 2014/2015, but limited real-time emergency generation (RTEG) to 600 MW in accordance with ISO rules. Active demand response clearing in that forward capacity auction totaled 1,982 MW region-wide and 521 MW in the Connecticut sub-area. Passive demand response clearing in that auction will provide 1,486 MW region-wide, including 419 MW in Connecticut.
- *Net Imports*. Net imports into New England are assumed to be constant at 1,911 MW for years 2015 through 2022, consistent with amounts cleared in ISO-NE's first five forward capacity auctions. This reflects 2,011 MW of imports and 100 MW of exports.

Projected Economic Retirement, Entry, and Active Demand Response

The analysis conducted by the Brattle Group recognizes that, in the market context, many key outcomes cannot be ensured or planned, but instead will be determined by the decisions of

12 Divergence between equipment capacity ratings and capacity values assigned by ISO-NE in resource adequacy analysis occurs because some resources (*e.g.*, solar and wind) frequently are not fully available during peak hours.

market participants, and therefore can only be projected. Projecting market participants' potential entry (in the form of new generation or additional demand response resources) and exit (in the form of retirement of generation or attrition of demand response) requires modeling of their financial decisions, which are based primarily on likely market prices and the ongoing costs of providing the capacity service. The Brattle Group's capacity market model simulates ISO-NE's forward capacity auctions and economic entry and exit decisions simultaneously, since the capacity prices influence individual economic decisions *and* reflect the combined results of those decisions. In the model, the annual demand for capacity is provided by the Net Installed Capacity Requirement projections; supply includes most existing and planned generation bidding as price takers (offering capacity at zero price and accept whatever price results), while potential retirement candidates, active demand response resources, and potential new entrants submit bids that reflect their net avoidable going-forward costs. The marginal capacity needed to meet the requirement sets the equilibrium capacity market price. Resources that offer capacity at a higher price than the market price (i.e., resources do not "clear" the auction) either retire or do not enter.[13]

The model results indicate that the Connecticut capacity price would not separate (differ) from the New England capacity price if the New England East-West Solution (NEEWS) transmission project, scheduled for completion in 2016, continues to be developed and receives the necessary approvals. This would allow Connecticut to meet its Transmission Security Analysis requirement even if all fossil steam units in Connecticut retired. However, there would be price separation in the Northeast Massachusetts/Boston area starting in 2016. The Department assumed that this need would be met by incremental energy efficiency (an amount that is less than that called for by the Massachusetts Green Communities Act), although ISO-NE is considering a proposal to meet this need with new transmission.

Generation retirement decisions are driven largely by capacity market prices and evolving environmental regulations, specifically regulations that control hazardous air pollutants (HAPs) such as mercury. The analysis assumes these regulations will require generators without certain pollution controls to install costly retrofits (Maximum Achievable Control Technology, or MACT) or retire in 2015. The U.S. EPA has also proposed many other regulations that will affect generators, but none of these yet clearly impose widespread, inflexible requirements for retrofits and compliance on par with the rule that controls hazardous air pollutant emissions. The Cross-State Air Pollution Rule (CSAPR), which was stayed in December 2011 pending judicial review, would exempt Connecticut and Massachusetts and, in any case, would impose allowance costs, not stringent control requirements. The EPA's plan to tighten ozone standards, which could lead to strict emissions rate limits, has been delayed and will likely not have a significant impact until the end of the 10-year study horizon. The proposed rules under the Clean Water Act Section 316(b) on cooling water intake structures appear to have flexible compliance mechanisms, and confer implementation discretion on states.

In order to determine which generation units would have to install specific controls to comply with Maximum Achievable Control Technology requirements for hazardous air pollutants, DEEP consulted with Connecticut generation owners and environmental agencies from other

[13] The forward capacity auctions have so far had a price floor that has determined the price in surplus conditions. This price floor will expire in the 2016/17 forward auction, which will be conducted in 2013.

states.[14] The Brattle Group analysis assumes that an electrostatic precipitator (ESP) would likely be needed on Middletown 4 and Montville 6 in Connecticut, and Yarmouth 1-3 in Maine to capture mercury emissions.[15] It further assumes the Schiller coal plant in New Hampshire and the Mt. Tom coal plant in Massachusetts would likely need activated carbon injection (ACI) to improve the effectiveness of their fabric filters or ESPs in capturing mercury. The Brattle analysis also assumes that the Bridgeport Harbor 3 coal unit would need dry sorbent injection (DSI) to control acid gases, as would the Schiller coal plant in New Hampshire. The capital costs of such retrofits range from \$12/kW to \$226/kW, as documented in Appendix E (Environmental Regulations).

The capacity model evaluates the economic implications of retiring versus retrofitting each unit by comparing the sum of retrofit costs and ongoing fixed operations and maintenance costs to the short term (3 year) net present value of energy margins and capacity revenues expected from continued operation. Energy margins are estimated in the DAYZER model, and capacity prices are estimated within the capacity model. The result was 1,687 MW of economic retirements regionally (in addition to the 1,549 MW already planning to retire) mostly occurring in 2015, the assumed compliance deadline for hazardous air pollution rules. In Connecticut, there would be 938 MW of economic retirements in 2015, in addition to 183 MW already planned. However, many of the old steam units in Connecticut that are not projected to need capital-intensive controls to comply with the hazardous air pollution rules would likely remain online because their going-forward fixed operations and maintenance costs are less than the projected capacity price. These units include the Middletown 2-3, Montville 5, New Haven Harbor and Norwalk Harbor 1-2 steam oil units. The Bridgeport Harbor 3 coal unit is projected to remain online despite the cost of installing dry sorbent injection.

The amount of active demand response in the market also requires estimation because market participants decide how much to provide largely based on capacity prices. Intuitively, one would expect that supply of active demand response would decrease when capacity prices fall (e.g., after the price floor is eliminated) and increase when they subsequently rise. For forecasting purposes, The Brattle Group constructed an active demand response supply curve with a fixed cost component, and a variable cost component (per MWh of expected interruption) that increases as total market demand response penetration increases to account for a greater probability of being called. Including this supply curve in the capacity market simulations caused projected active demand response to decrease from 1,982 MW already cleared in the fifth capacity auction for 2014/15 to 1,006 MW when the price floor is eliminated; projected active demand response would then rise to 2,588 MW in 2022 when capacity prices are expected to be substantially higher.

New generation entry is assumed to occur only when the capacity price rises to the Net Cost of New Entry (Net CONE) of the most economic generation technology in New England: a gas-fired combined-cycle plant. The Net Cost of New Entry of a new combined-cycle plant is

14 These estimates are only intended for the purpose of this analysis, not as a regulatory determination of actual control requirements.

15 An electrostatic precipitator is a device that removes dust or other finely divided particles from power plant exhaust by charging the particles inductively with an electric field, then attracting them to highly charged collector plates.

provided by the annual capital carrying charges and fixed operating and maintenance costs, minus the energy margins and ancillary services revenues it would earn, as estimated in the DAYZER model. The annual capital carrying charges and fixed operating and maintenance costs are assumed to be $138/kW-year (in 2012 dollars), based on the costs The Brattle Group recently estimated for PJM Interconnection LLC for a new combined-cycle plant in New Jersey, which are increased by 4.7% to account for higher labor costs in Connecticut.[16] At these costs, no new combined-cycle capacity would enter until 2022-2023 in the Base Case. In the meantime, other lower cost resources, such as active demand response, would be expected to meet the Net Installed Capacity Requirement and set capacity auction clearing prices.

Projections for Capacity Prices and Resource Adequacy

Capacity prices through 2015-2016 are given by the administratively determined price floor.[17] After the price floor expires, DEEP expects prices to reflect the supply and demand conditions summarized above.[18] The capacity model is considered solved when the market clears, with capacity prices that are consistent with the modeled economic exit and entry decisions. Projected prices are expected to fall below $1/kW-month to clear most of the capacity surplus that the price floor was supporting. As Figure 5 shows, prices are then projected to rise as load grows and higher-cost demand response re-enters. Capacity prices become progressively higher until new generation is needed and prices reach the Net Cost of New Entry level ($7.1/kW-month) in 2022-2023.

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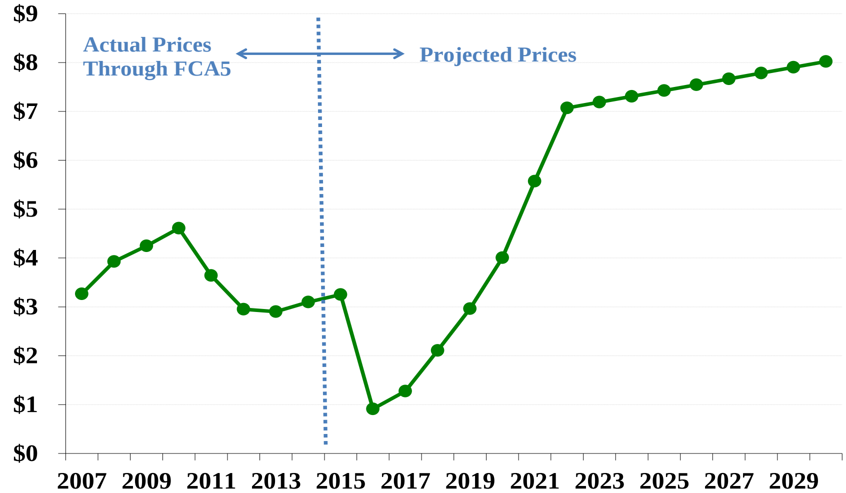
16 The key parameters are $929/kW overnight cost, 13.1% level-real capital charge rate (based on 8.5% merchant ATWACC and 20-year economic life), and $17/kW-yr fixed operations and maintenance costs, for a 656 MW combined cycle. These estimates are based on "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM," adjusted to account for higher labor costs in Connecticut. *See* http://www.pjm.com/~/media/committees-groups/committees/mrc/20110818/20110818-brattle-report-on-cost-of-new-entry-estimates-for-ct-and-cc-plants-in-pjm.ashx.

17 In the analysis, capacity prices paid to generators are prorated when the price floor is binding and surplus capacity clears.

18 At the time the analysis for the 2012 IRP was conducted, the price floor was set to expire after the auction for the 2015-2016 delivery year. Shortly after the analysis and draft report were completed, ISO-NE stakeholders voted to extend the price floor for another year, subject to FERC approval. DEEP did not incorporate that change into the IRP analysis because of time constraints. However, the likely one-year extension of the price floor is not expected to alter the regional supply fundamentally from the projections presented in the 2012 IRP. Many of the retirements are still likely to be driven by environmental requirements; other market dynamics may occur a year later than projected. In any case, the IRP projections should be considered approximate and uncertain due to the uncertainties surrounding future auction rules, environmental regulations, and market conditions.

Figure 5
Projected Capacity Prices (2012$/kW-month)



The resulting supply and demand for resources is described in detail in Appendix B (Resource Adequacy). The bottom line is that all of ISO-NE's reliability requirements affecting Connecticut can be expected to be met through 2022, without having to plan or facilitate new generation resources. These requirements are discussed in more detail below.

First, with respect to the **Connecticut Local Sourcing Requirement**, the projections indicate that there are adequate resources in Connecticut to meet the Transmission Security Analysis criteria well beyond 2022, with 600 MW of surplus in 2015-2016, and then 1,900 to 2,000 MW of surplus in 2016-2017 and beyond. The surplus is likely to remain approximately constant after the price floor is eliminated, since demand response is likely to exit initially but then return as load grows and capacity prices rise. Resources are shown as stacked bars in Figure 6, clearly exceeding the requirement shown in black. Projected retirements, shown as empty boxes at the top of the stacked bars, are not sufficient to eliminate the surplus.

It is important to point out that this projection assumes that the various components of the planned New England East-West Solution (NEEWS) transmission project will be completed. The NEEWS project is planned to address several transmission security reliability issues, and it will also support local resource adequacy in Connecticut as a side benefit. DEEP assumes that the NEEWS transmission enhancements will increase Connecticut's import capability by 1,100 MW (shown on Figure 6 as a reduction in the local requirement) and electrically incorporate the Lake Road generating facility (745 MW) into the Connecticut sub-area.

Two of the components of NEEWS—the Rhode Island Reliability Project and the Greater Springfield Reliability Project—are currently under construction. The remaining two components—the Interstate Reliability Project and the Central Connecticut Reliability Project—are not yet under construction. They were included in the IRP Base Case because they have received the required ISO-NE technical approvals. The relevant state siting boards, however, have yet to review the siting impacts and the reliability need for these components. State siting reviews will be informed by ISO-NE's forthcoming reliability assessment, which will be updated to account for currently-projected system conditions. State siting hearings for the Interstate Reliability Project are underway in Connecticut and will be filed soon in Massachusetts and Rhode Island. State siting permit applications for the Central Connecticut project have not yet been filed.

If the Interstate and Central Connecticut projects are not approved, the Connecticut import capability would be 1,000 MW less than assumed for years 2016 through 2022 in the IRP Base Case, and the 745 MW Lake Road generating facility would not be incorporated electrically into Connecticut. Local resource adequacy would still be maintained, but with a smaller surplus of only approximately 200 MW between 2016 and 2022 (compared to 1,900-2,000 MW in the Base Case).

If, on the other hand, all components of the NEEWS project are completed as planned, Connecticut's local resource adequacy would be maintained even if all 2,716 MW of the fossil steam capacity in Connecticut retired (compared to 1,112 MW of retirements projected). Even with the completion of NEEWS, a 350 MW shortfall could occur in an unlikely scenario where: (1) all fossil steam units retire; (2) ISO-NE's "high economic growth" forecast is realized (about 350 MW higher Connecticut load by 2022 than in the Base forecast); and (3) all 400 MW of old aero-derivative combustion turbines retire due to potential future NOx regulations. Such a large number of steam and combustion turbine retirements is unlikely because these units appear to be economic under future market conditions. Even if a few more units retired than projected, capacity market prices would increase, providing additional incentive for the remaining units to stay online. Furthermore, for those potential retirements that might pose a local reliability concern, ISO-NE could resort to offering reliability must-run contracts.[19] The potential challenges from increased retirements would be greater if the Interstate and Central Connecticut Reliability Projects are not constructed.

Until the uncertainties surrounding the Interstate and Central Connecticut component of NEEWS are resolved, DEEP will continue to monitor the supply, demand, and transmission situation and assess whether any local resource adequacy shortfalls could occur. In the event of any ISO-NE determination that the Interstate and Central Connecticut portions of the NEEWS project are no longer needed, DEEP will initiate a process to determine if additional resources are needed for reliability, and will amend the IRP as appropriate.

Second, with respect to the **Locational Forward Reserve Market**, the Brattle Group's modeling shows that there are more than adequate resources projected to meet Connecticut's Locational Forward Reserve Market requirement. ISO-NE's 2011 Regional System Plan indicates that, through 2015, Southwest Connecticut will have no such requirement, while Greater Connecticut may need 400 to 1,000 MW of quick-start capacity.[20] The model projects 1,501 MW available in Greater Connecticut, including 949 MW in Southwest Connecticut, well above the projected need in each area.

[19] Such contracts may only provide a temporary solution, as their duration would have to conform to the environmental compliance deadlines.

[20] See http://www.iso-ne.com/trans/rsp/2011/index.html.

Finally, with respect to the **Net Installed Capacity Requirement for New England**, adequate resources are projected for meeting the Net Installed Capacity Requirement through 2022. As Figure 7 shows, the stacked bar depicting supply exceeds the requirement through 2015. Thereafter, without a capacity price floor to maintain surplus capacity, the forward capacity auctions clear just enough supply to meet the requirement. Generation retirements and demand response attrition are sufficient to eliminate the surplus in 2016. Re-entry of existing demand response compensates for load growth through 2020, and additional demand response meets further load growth through 2021. By 2022, new generation entry begins to become economic. These conclusions are based on our simulated generation retirements and entry by demand response providers, as discussed above.

Figure 6. Locational Resource Adequacy in Connecticut

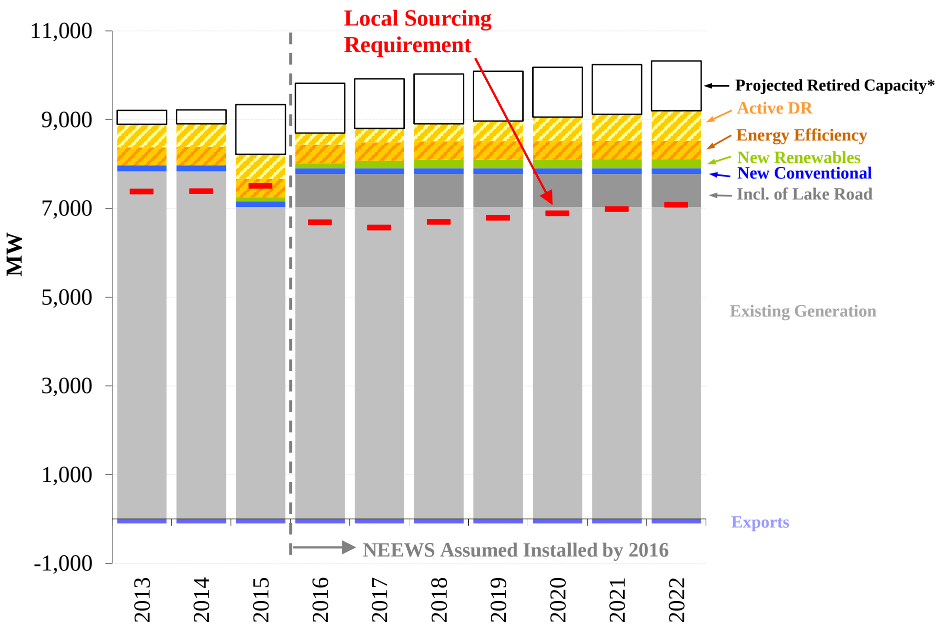
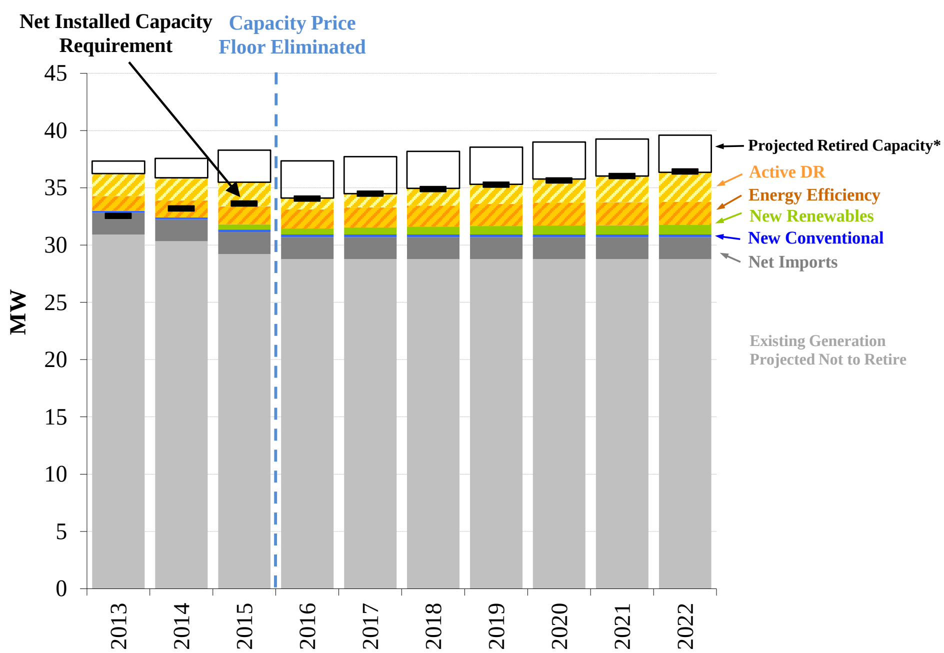


Figure 7. Resource Adequacy in New England



Even if these projections and assumptions (such as assuming regional imports remain constant at approximately 1,900 MW) turn out to be wrong, the capacity market is designed to self-correct for such "errors" and to restore a balance between resources and prices. For example, if an additional generating unit retired, capacity prices would increase, which would reduce the incentive for any further retirements and would enhance incentives for additional demand response to enter the market.

Winter Generating Fuel Availability

There is an additional type of resource adequacy that does not correspond to any current ISO-NE requirement: preparedness for severe winter cold snaps, when there may be limited natural gas available for natural gas-fired generating units. In New England, most natural gas-fired generators lack firm gas pipeline delivery, although Mystic 8 and 9 (1,679 MW winter capacity) have their own liquefied natural gas (LNG) supply source, and over 1,600 MW of other generators currently have firm mainline gas transportation in New England.[21] An additional 5,300 MW of capacity has dual-fuel capability, yielding over 8,500 MW of natural gas-fired generators that currently have nominally reliable fuel supplies.

In the IRP Base Case energy market simulations, some level of natural gas-fired capacity is required to meet peak winter electricity loads in each of the three study years. Although a substantial amount of natural gas-fired capacity currently has dual-fuel capability or firm gas supplies, there is no requirement for generators to maintain reliable access to fuel, and thus the firmness of these fuel supplies cannot be verified or regularly tested. In addition, the "just-in-time" natural gas delivery system stresses both the natural gas system (e.g., causing pressure problems and unavailability of non-firm capacity) and the electric system (e.g., causing operational issues) during tight winter conditions.

DEEP recognizes that, for the longer term, the issue of natural gas reliance in winter warrants continued close monitoring, since a number of uncertain factors will influence the degree to which the electric system depends on natural gas-fired capacity that may lack firm fuel supplies or dual-fuel capability. These factors include retirements of oil and coal-fired generation; the extent to which natural gas units with firm fuel or dual-fuel capability maintain that capability; and the extent to which the electric system can rely on natural gas-fired generators without firm fuel supplies. This is a complex issue that requires further analysis, potentially including modeling cross-system dependencies between the electricity and gas systems to fully understand their interactions under stress conditions. ISO-NE is examining this issue under its Strategic Initiative. DEEP is monitoring the ISO-NE initiative and will engage in the ISO process as necessary. DEEP will also assess the compliance of Connecticut generators with their siting requirements and contractual obligations regarding backup fuel capabilities.

In December 2011, ISO-NE released a presentation based on a draft report assessing New England's natural gas pipeline capacity to satisfy power generation needs.[22] That presentation suggested that regional natural gas supply capability is inadequate to satisfy regional gas demands on a winter design day over the next decade. The presentation did not focus on electric reliability. For example, it did not explicitly take into consideration the substantial amount of

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[21] Of this 1,655 MW with firm gas capacity, about 500 MW is in Connecticut: Lake Road (246 MW worth of firm gas), Milford Power (218 MW), and Wallingford/Pierce (35 MW).

[22] *See* "Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Power Generation Needs," presented by ICF International to ISO-NE Planning Advisory Committee, December 14th, 2011.

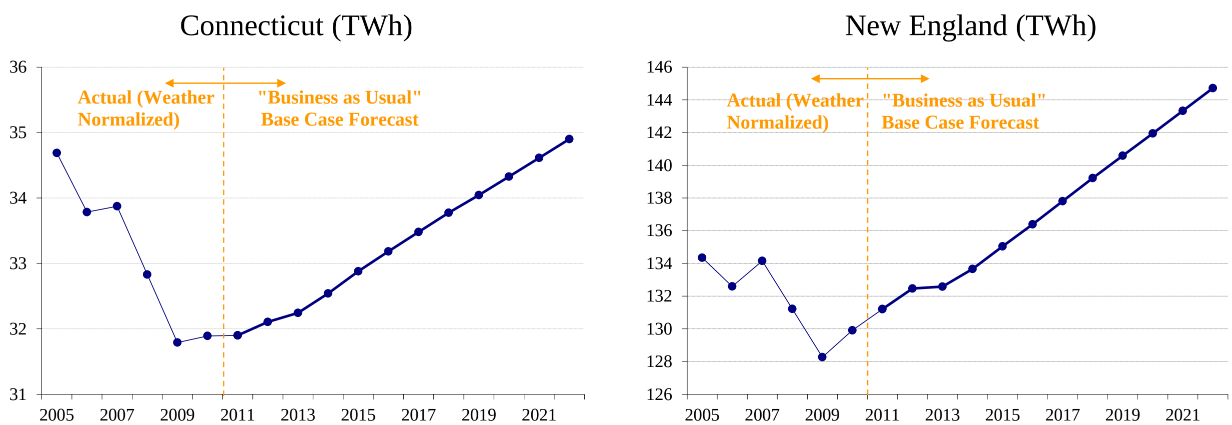
natural gas-fired capacity that is dual-fuel capable and can operate on its alternative fuel if necessary.

B. Demand and Supply of Energy

Connecticut's electric energy consumption has declined sharply since 2005 due to several factors, including the economic slowdown and continued implementation of energy efficiency measures. Looking forward, Connecticut's energy consumption is expected to grow at approximately 1% per year, not reaching 2005 levels again until 2022. The rest of the New England region has not declined as sharply and is projected to recover at 1.1% annually, as shown in Figure 8.[23]

Because DEEP's projections show that adequate capacity will be available, as discussed above, DEEP also expects that energy requirements can be met reliably. *How* energy is produced, and the wholesale price of that energy, will depend on fuel prices, the types of resources that are developed or retired in the future, and transmission constraints. For the IRP, the DAYZER market simulation model was used to analyze how energy is produced. DAYZER includes all of the key elements of energy supply and demand, as well as all existing and planned transmission facilities in the ISO-NE system.

Figure 8
Annual Energy Consumption — Historical and Forecast for CT and New England[24]



One of the most important inputs is natural gas prices, with the prices of coal, oil, and emissions allowances also influencing wholesale market outcomes to a lesser extent. Natural gas prices are based on NYMEX Henry Hub futures through 2021. The 2012 IRP relied on futures traded between 8/5/11 and 9/16/11, which were priced at \$4.10/MMBtu for near-term delivery, rising to

23 These figures are net of energy efficiency that has been implemented to date, some future energy efficiency measures that will be implemented to fulfill commitments made in ISO-NE's forward capacity auctions through 2014-2015, and some amount of energy efficiency impacts that are embedded implicitly in the forecast as a continuation of "business-as-usual" trends. There are a number of challenges to fully and accurately account for energy efficiency in the load forecast that are discussed in Appendix B (Resource Adequacy) and Appendix C (Energy Efficiency).

24 Year 2009 and 2010 weather normalized energy consumption figures for Connecticut are estimates supplied by The Brattle Group.

$5.21 by 2015, $5.40 by 2017, and $5.92 by 2022.[25] Delivered natural gas prices also include a basis differential based on historical prices and NYMEX basis swaps ($1.06/MMBtu on average, with a January high of $3.12/MMBtu), plus a $0.30/MMBtu charge for generators served by local gas distribution companies instead of directly by a pipeline.[26] Oil prices are much higher, based on current forward prices. Coal prices, affecting approximately 2,000 MW of capacity in New England with Salem Harbor and AES Thames retired, are $4/MMBtu, which is high in historical terms. Coal prices are based on NYMEX Central Appalachian futures plus transportation costs.

Emissions allowance prices for NOx are assumed to stay at $0/ton because of Connecticut's exclusion from the Cross-State Air Pollution Rule (CSAPR) and because it is unlikely that the anti-backsliding provisions of that rule would be invoked under projected emission levels. (CSAPR was recently stayed by the D.C. Circuit Court of Appeals, but the analysis for this IRP assumes it will eventually proceed to implementation.) Prices for SO_2 allowances also are assumed to be $0/ton because of Connecticut's exclusion from the Cross-State Air Pollution Rule and because emission reductions in other states will keep emission allowance prices under the Clean Air Act Title IV acid rain program essentially at zero. Prices for CO_2 allowances are assumed to stay at roughly $2/ton, set by the Regional Greenhouse Gas Initiative (RGGI) price floor.[27] The analysis also assumes that no national climate policy based on cap-and-trade or carbon taxes will be implemented over the 10-year study horizon.

Using these data inputs, the DAYZER model simulates ISO-NE's operation of the electrical system and its administration of the energy market. The outputs of the model include hourly locational marginal prices (LMPs), dispatch costs, generation and emissions for every generating unit in New England, and transmission flows and congestion costs. The resulting annual average wholesale energy prices paid by Connecticut loads are $54.6/MWh in 2015, $56.3/MWh in 2017, and $61.5/MWh in 2022 in constant 2012 dollars, as shown in Figure 9, which also depicts monthly wholesale energy prices.[28] For comparison, annual average prices in 2008 were $87/MWh (when natural gas prices were much higher), then dropped to $45/MWh in 2009 before rising to $52/MWh in 2010 (all in 2012 dollars). About two thirds of the expected increase over time is due to rising natural gas prices. The remaining one third of the expected increase is due to less efficient generators setting market prices in more hours (higher "market heat rate") as the initial capacity surplus shrinks and load grows.

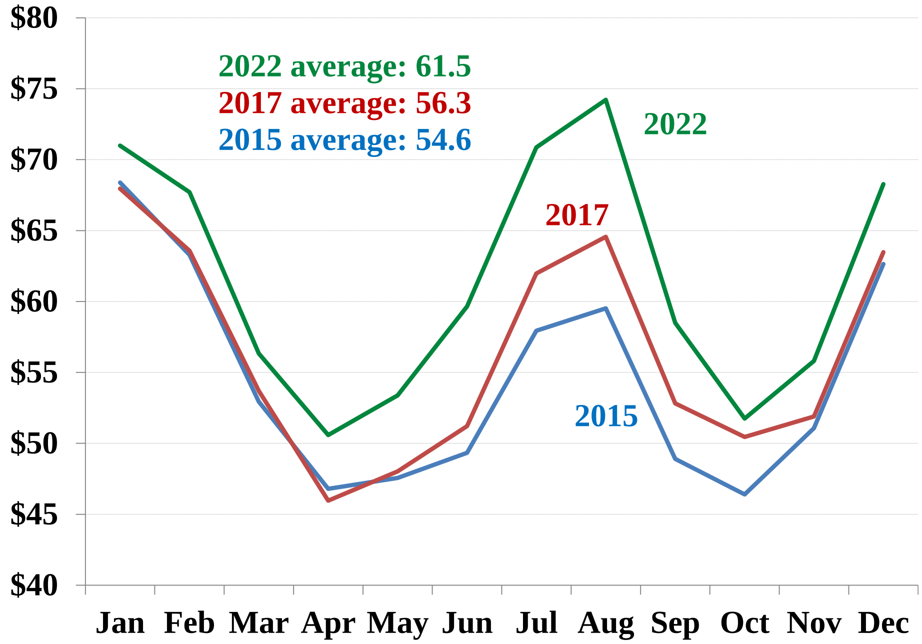
[25] Since the IRP analysis was conducted, natural gas prices have decreased. As of June 13, 2012, NYMEX Henry Hub Futures have decreased by roughly $1.40 per MMBtu (in 2012 dollars) for delivery in 2015 through 2020

[26] "Henry Hub" is a common reference pricing point located in Louisiana. "MMBtu" is one million British Thermal Units. All prices shown are annual averages, expressed in 2012 dollars.

[27] RGGI expires in 2018. This analysis assumes CO_2 prices remain the same thereafter, but such a low price has a trivial effect on the results.

[28] Load-weighted annual average energy prices are $65.3/MWh in 2015, $59.2/MWh in 2017, and $57.1/MWh in 2022 in constant 2012 dollars. Load-weighted average prices are greater than simple average prices because load is frequently higher when prices are higher.

Figure 9
Base Case Projection of Energy Prices (2012 $/MWh)

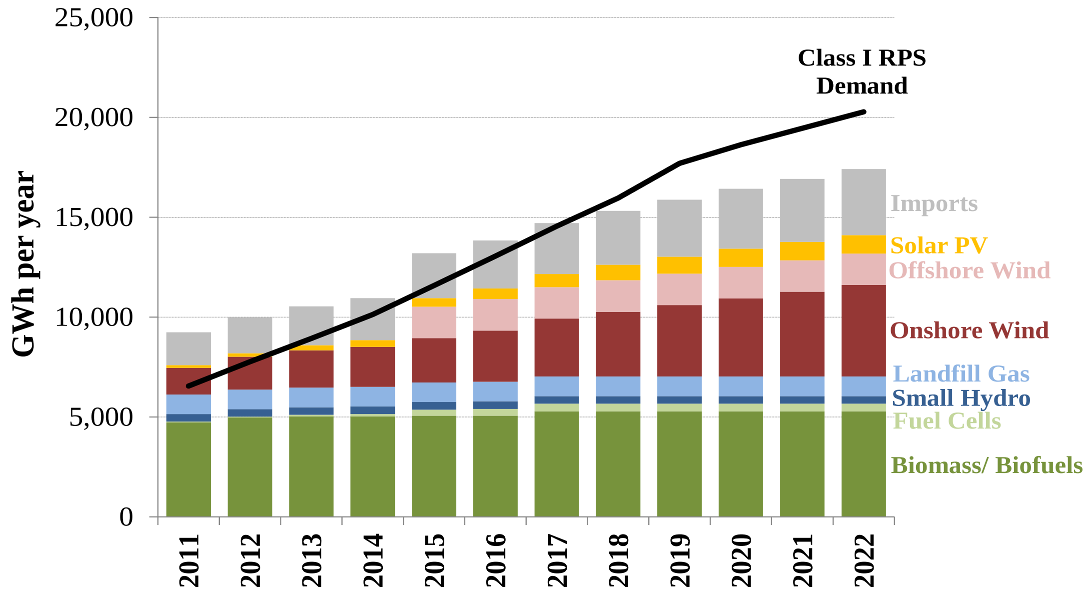


C. Supply and Demand for Renewable Generation

The demand for Class I renewable energy resources in New England is expected to almost triple over the next decade based on current state Renewable Portfolio Standard (RPS) rules and regulations. Among the New England states, Connecticut has the most ambitious Class I target as a percentage of load (12.5% in 2015, increasing up to 20% by 2020) and accounts for approximately one third of the regional renewable energy demand (second only to Massachusetts). Load serving entities in New England rely on a regional market for Class I Renewable Energy Credits (RECs) to comply with RPS requirements. Connecticut's regulations have some unique eligibility characteristics, with some resources qualifying for Class I status only in Connecticut. In estimating the supply and demand balance of the regional Class I REC market, the analysis has taken into account resources that are specific to Connecticut.

While the technical potential of renewable resources in the overall New England region remains high, tighter financial conditions over the past three years have made it increasingly difficult for new renewable resources to secure funding for construction. Based on information that is currently available, our Base Case projection of Class I renewable energy resources build-out shows that New England is likely to meet the regional demand through 2017, but may fall short in years beyond 2017. The projection through 2015 is based on information for projects that are currently under development as well as state-specific programs (including Connecticut's Project 150 and the ZREC/LREC programs). For years beyond 2015, DEEP presents a "likely" trajectory of renewable development based on recent historical trends and expected near-term additions. These assumptions include: (a) growing onshore wind capacity by about 115 MW per year; (b) adding new solar resources to meet carve-outs from targeted state programs; (c) not building new landfill gas and small hydro resources; and (d) increasing the eligible Class I REC imports from New York and Canada at approximately 10% per year. Figure 10 summarizes supply and demand for Class I renewable energy in New England.

Figure 10
New England Class I Renewable Resource Supply and Demand Balance



Under the Base Case, Class I renewable cost assumptions and simulated REC market, the market price for Class I RECs would be approximately $23/MWh while the market is in relative surplus (2012 through 2017). Beyond 2017, however, the REC shortfall implies that REC prices would rise to the level of the Connecticut Alternative Compliance Payment (ACP), which currently is the lowest in New England.[29] REC prices would clear the market at $55/MWh ($45/MWh real 2012 dollars), which is the level of the Connecticut Alternative Compliance Payment. Brattle estimates that the cost of complying with the Class I requirements will increase from $118 million in 2012 to $445 million in 2022. Under these conditions, Connecticut utilities would satisfy nearly half of their RPS obligations through Alternative Compliance Payments. These payments could be avoided if the pace of renewable energy development accelerates in the New England region. For example, more projects could be developed if transmission is constructed to access remote onshore wind resources, if costs decline more than expected, or if financing improves. Connecticut or other states could also consider offering long-term purchase power contracts to provide a more reliable revenue stream to renewable energy projects.

In addition, DEEP evaluated Class II and Class III supply and demand. Overall Class II and III supply and demand is summarized in Appendix D. Class II requirements are initially set at 3% and currently no change in that level is anticipated. The current supply of Class II and Class III resources significantly exceeds the existing RPS requirements. This drives the Class II REC

29 Alternative Compliance Payments (ACP) represent an administrative cap on REC prices, which entities can pay to states in lieu of purchasing RECs if they are unavailable or too expensive. Other New England states have indexed their ACP to inflation, while Connecticut set the level at $55/MWh without providing for any inflation adjustment. Other New England states' ACP levels for Class I requirements are currently $62/MWh, escalating at the consumer price index.

prices down to less than $5/MWh and the Class III REC price to the price floor of $10/MWh and prevents some of the resources from receiving any REC payments at all.

Resource recovery facilities largely comprise Class II generation in Connecticut. Historically, long-term contracts with the EDCs have been necessary to ensure the economic viability of these facilities with the expectation that proceeds from the Class II market would provide a sustainable future revenue source. However, many long-term contracts have ended the Class II market is currently oversupplied, energy prices have declined and operating costs have increased. Reduced revenues, unsold RECs and increased costs have created financial hardship and raise concerns about significant environmental consequences for the future of the State's management and disposal of trash. Additional concerns such as higher tipping fees for municipalities and electricity market conditions must also be considered as DEEP evaluates potential solutions to this immediate problem and develops a plan to address the continued viability of these facilities.

Conservation and energy produced by combined heat and power facilities comprise Connecticut's Class III market. Sales of Class III RECs provide an estimated $4.5 million in supplemental revenues for utility conservation programs. This additional funding, while helpful, is not essential to the utility conservation effort. Oversupply in the Class III markets has resulted largely from continued growth in energy efficiency programs and has impacted third-party conservation efforts. Low REC prices have also impacted existing CHP units and reduced incentives for additional development. The Class III requirement and associated market needs to be reevaluated if Connecticut is to continue to support combined heat and power and/or third-party sponsored energy efficiency through the RPS**.**

DEEP estimates the cost of Class II RECs to be approximately $4.5 million in 2012. The cost of Class III RECs is estimated at $13 million. These costs should remain about the same through 2020 since the RPS requirements do not change. Utility conservation will increase, keeping REC prices at the floor level and making more Class III RECs unmarketable. Class II REC prices and costs should also remain the same unless some of the existing resource recovery facilities retire.

D. Outlook for Customer Rates

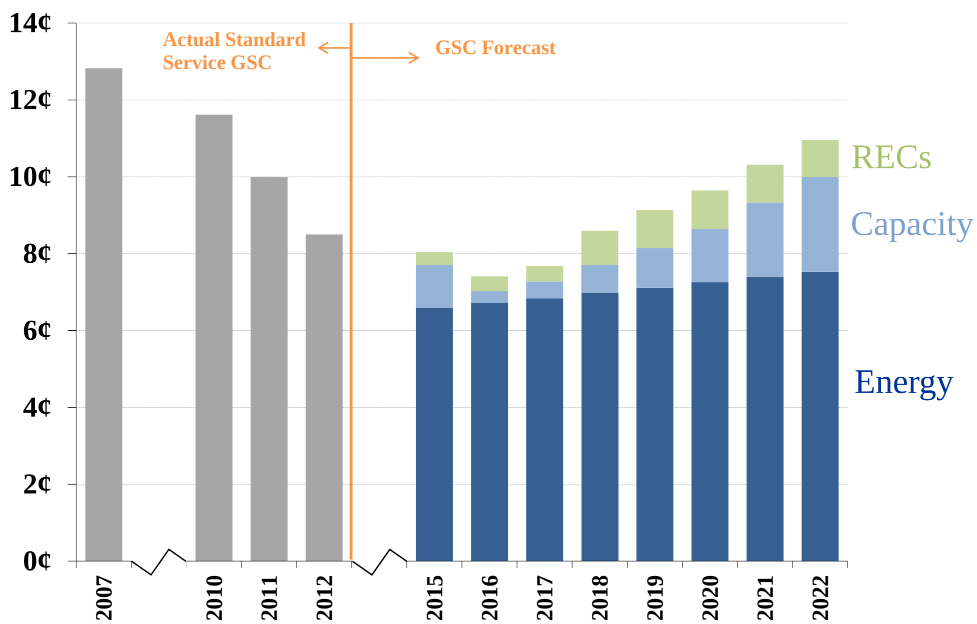
The IRP analysis projects Generation Service Costs (GSC) for Connecticut customers, averaged across all rate classes. Generation Service Costs currently comprise approximately half of the total customer bill. Based on the capacity, energy,[30] and REC market projections described above, DEEP projects that Generation Service Costs should remain relatively constant in real terms, at approximately 8 ¢/kWh from 2012 through 2017, as shown in Figure 11.[31] That is substantially lower than rates experienced over the past several years, primarily because Henry Hub natural gas prices are expected to remain below $6/MMBtu and capacity prices are expected

[30] In Figure 11, "energy" costs include the costs of electrical loss net of loss refunds, congestion costs net of financial transmission rights (FTR) revenues, and an estimated 10 percent adder to account for other ISO-NE charges and a risk premium.

[31] The Generation Service Costs shown in Figure 11 do not include other components of customer bills, such as transmission and distribution (T&D) costs, the net costs of mandated renewable investments (ZREC/LREC or Project 150 programs), or the cost of long-term contracts with the Kleen Generation, AMERESCo energy efficiency, Waterbury Generation or Waterside Generation and the new peaking facilities.

to stay below $4/kW-month. For comparison purposes, Figure 11 shows estimated historical and current rates for Standard Service for residential and small commercial and industrial customers in 2007, 2010, 2011, and 2012.[32]

Figure 11[33]
Annual Average Generation Service Costs for Connecticut Customers (2012 ¢/kWh)
Base Case Projection



From 2017 to 2022, Generation Service Costs are likely to increase by slightly more than 3 ¢/kWh, as shown in Figure 11. This projected increase is driven by three factors. First, 1.9 ¢/kWh of the increase is from rising capacity prices. In 2017, prices will likely reach their lowest levels of about $1/kW-month after the current price floor expires and the market price drops to clear the existing capacity surplus. Thereafter, prices will rise as regional load grows. By 2022, prices will likely rise to $7/kW-month, near the equilibrium levels customers can expect to pay on a long-term average basis in order to attract new generation resources.

Second, 0.6 ¢/kWh of the increase is from the cost of Renewable Energy Credits (RECs) and Alternative Compliance Payments (ACP). The volume of renewable energy purchased increases as the Class I requirement increases, but the price also increases as the scarcity of regional supply causes the REC price to be set by the Connecticut Alternative Compliance Payment. In addition, outside the Generation Service Charge, there would be approximately a 0.2 ¢/kWh increase for transmission to support increased Class I resources, although the cost is highly

[32] Estimated Standard Service rates shown in Figure 11 are based on a weighted average of filed rates for CL&P (80%) and UI (20%), converted to 2012 dollars. These rates apply only to residential and small commercial and industrial customers that choose to take retail service from the Electric Distribution Companies. Hence, these rates are not strictly comparable to the projected future rates shown in Figure 11, which represent an average across all customers in the state.

[33] In nominal terms, rates are estimated at 8.49 ¢/kWh in 2015, 8.45 ¢/kWh in 2017, and 13.29 ¢/kWh in 2022

uncertain and the modest rate impact assumes Connecticut pays for only its 25% load-ratio-share of the total estimated transmission costs.

Third, 0.6 ¢/kWh of the increase is from rising energy prices, approximately two-thirds of which is caused by natural gas prices rising, and one-third is caused by market heat rates increasing as load grows.

In this IRP, DEEP has identified and evaluated various opportunities to counteract some of the rate increases projected for the 2017-2022 period. One general approach is to help customers reduce the volume of consumption, and thus save money, especially when rates are higher. Another approach is to facilitate the development of low-cost resources that are economic (but may face barriers to implementation), which could defer the market price increases necessary to attract higher-cost resources. A third is to find more cost-effective ways to meet the clean energy objectives of the RPS. The Resource Scenarios section of this IRP addresses all of these approaches. As discussed below, DEEP concludes that increased energy efficiency can help meet all of these objectives and counteract more than half of the projected cost increases through 2022.

In addition to these resource approaches, DEEP is cognizant of the impact ISO-NE has on shaping the regional energy market. As such, DEEP will continue to participate actively in the ISO-NE stakeholder process to ensure that the market is working effectively to achieve reliability objectives at reasonable cost, and to ensure that the market reasonably accommodates Connecticut's energy policy objectives. DEEP will also be issuing a separate report that examines trends for all rate components, identifying factors impacting rates and providing recommendation to lower electric rates and bills for Connecticut customers. DEEP will issue this report in compliance with Section 90 of Public Act 11-80.

E. Fuel Use and Emissions Outlook

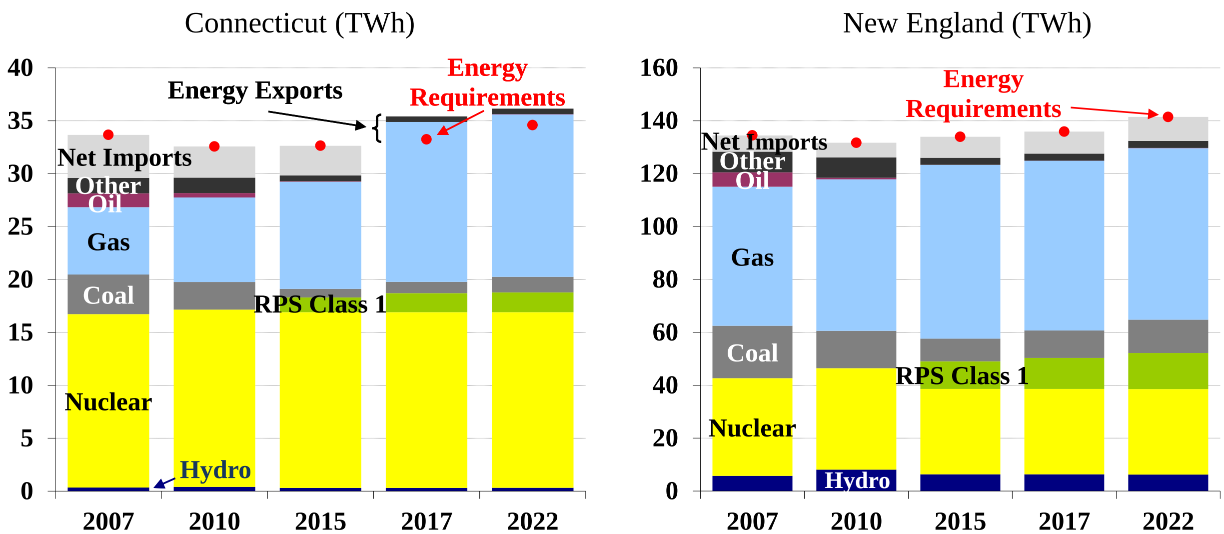
Electricity production and prices in New England today are markedly different from what the region experienced in the past decade. DEEP expects further changes over the next ten years. The primary reason for these past changes are dramatic shifts in relative fuel prices (reflecting low natural gas prices coupled with high coal and oil prices) while environmental retrofits, economic retirements, and new renewable generation will have increasing influence in the coming decade. For example, oil-fired generation decreased after 2007 partly because of increased availability of lower-cost natural gas-fired generation and renewables, but also because of changes in fuel prices. Oil prices have risen dramatically relative to natural gas prices, and are expected to remain high.

The combined effect of these changes on total generation by fuel type is shown in Figure 12 below, which includes 2007 actual data and projections for 2015, 2017, and 2022 for Connecticut and New England.[34] This shows the increase in renewable generation from 6% of total New England supply in 2007 to 10% in 2020, a 36% reduction in coal generation, and a steep decline in oil generation. Total generation in Connecticut has increased, mostly because of

[34] Regional natural gas and oil generation for historical years are estimated by The Brattle Group based on publicly-available data from ISO-NE. For forecast years, generation is simulated in the DAYZER model.

the 2011 addition of the Kleen generation facility, an efficient 620 MW natural gas-fired combined-cycle plant; with the expectation that Lake Road (a 745 MW natural gas-fired combined-cycle plant) will be electrically incorporated into the Connecticut sub-area upon completion of the Interstate portion of the New England East-West Solution transmission project at the end of 2015. These changes would convert Connecticut from a net energy importer to a net exporter by 2017.

Figure 12. Base Case Projection of Annual Generation by Fuel Type



DEEP projects that displacement of coal and oil generation by gas and renewable generation will continue to produce a dramatic reduction in regional NOx, SO_2, and CO_2 emissions relative to historic levels.

- *CO_2.* As shown in Figure 13, Connecticut CO_2 emissions have already decreased from 9.7 million tons in 2007, and are projected to decrease to 7.8 million tons by 2015 then slowly rise to 8.5 million tons by 2022. New England as a whole is expected to follow a similar curve, staying well below the targets established under the Regional Greenhouse Gas Initiative.[35]
- *SO_2.* As shown in Figure 14, Connecticut's power sector SO_2 emissions are expected to be a small fraction of past emissions. For example, 2010 emissions were 70% lower than in 2007; 2015 emissions are projected to be another 45% lower than 2010 emissions. By 2022, emissions are projected to grow back to 90% of 2010 levels, but still 73% below 2007 levels.
- *Annual NOx.* Figure 15 shows a substantial reduction in Connecticut's power sector NOx emissions, with only modest increases after 2015 as load grows. For example, 2010 emissions were 36% lower than 2007 emissions; 2015 emissions are projected to be half of that. After 2015, emissions are projected to grow slowly back to two-thirds of the 2010 level by 2022.

[35] In Figure 13 through Figure 16, "RPS Class I" includes biomass and fuel cells that are RPS-qualified. "Other" includes refuse and biomass that are not RPS qualified.

- *High Energy Demand Day NOx.* Figure 16 shows NOx emissions on just the top 10 High Energy Demand Days (HEDD), both for Base Case normal weather and for "90/10" weather representing a hottest summer expected in 10 years. These projections compare favorably to an average of 30 tons per day experienced on the 4 hottest days in each of 2007 through 2010, and the target level of 42.7 tons per day that Connecticut has committed to the Ozone Transport Commission.

Figure 13. Annual CO_2 Emissions

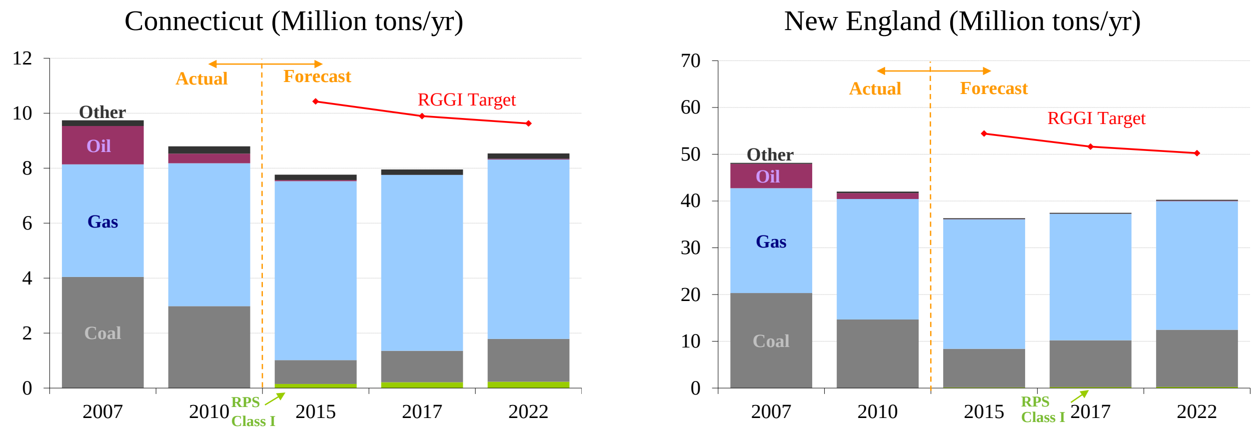


Figure 14. Annual SO_2 Emissions

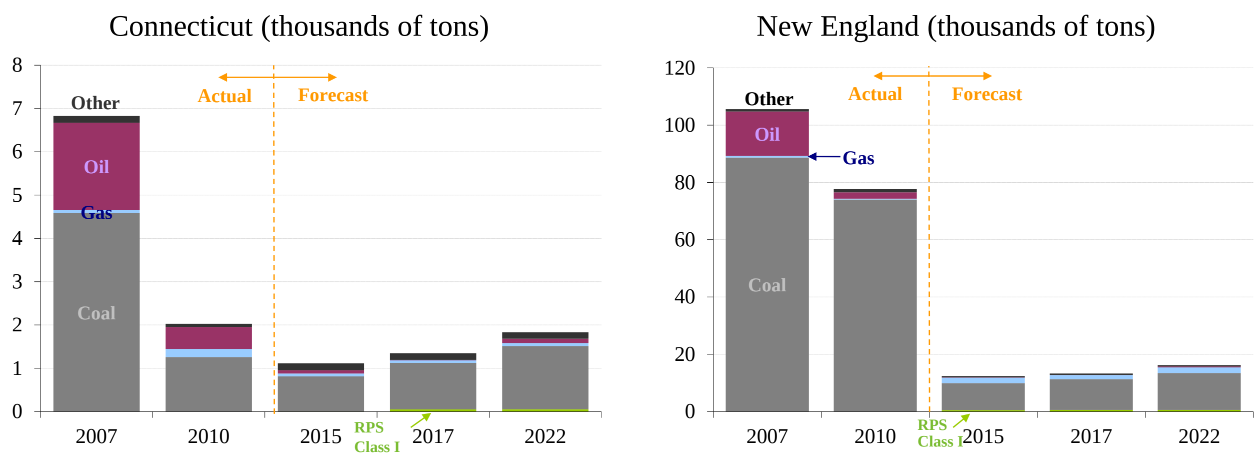


Figure 15. Annual NO_X Emissions

Connecticut (thousands of tons) | New England (thousands of tons)

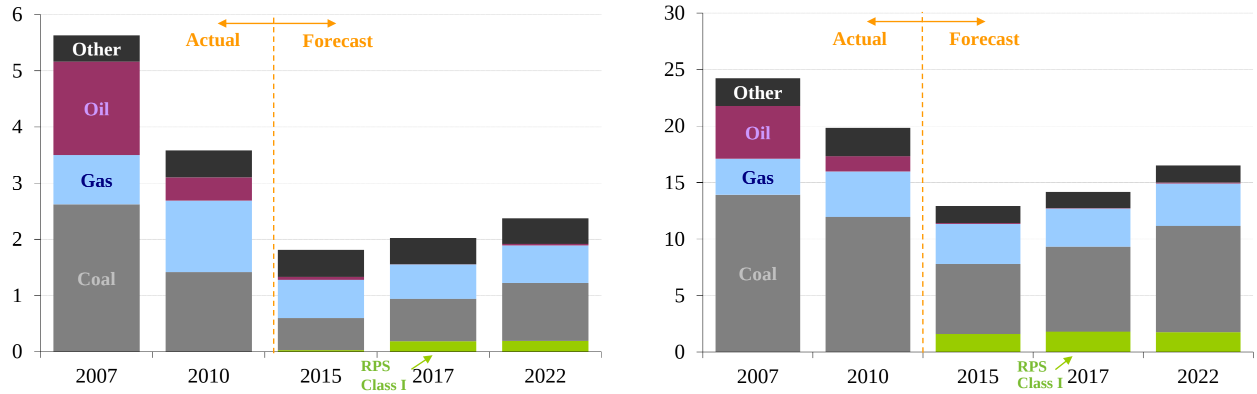
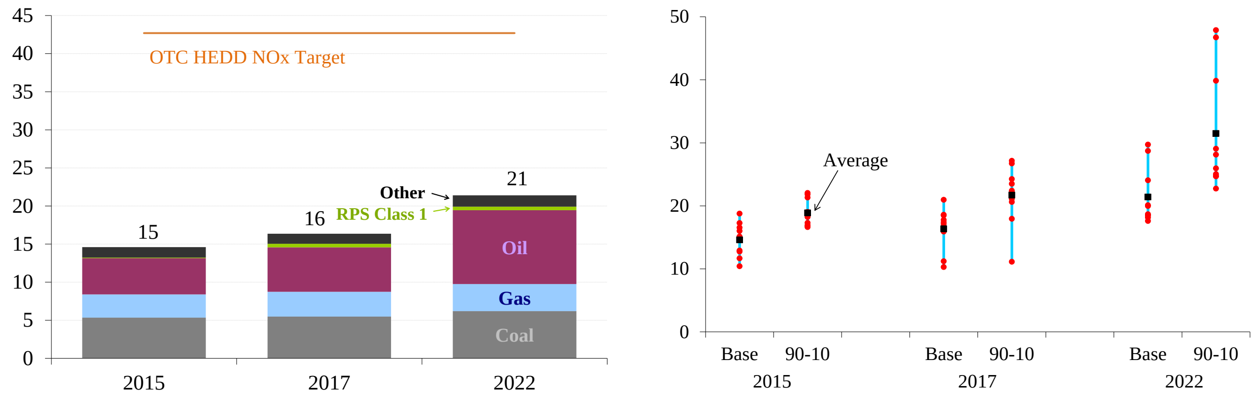


Figure 16. HEDD NOx Emissions in Connecticut (tons per day)

10-Day Average, by Source | Emissions on Each of 10 HEDD Days



V. ALTERNATIVE FUTURES

A. Definition of Futures

Long-range planning analysis must address uncertainty in order to be useful. Regardless of the effort and attention that goes into the analysis, it is impossible to perfectly predict key external factors—such as natural gas prices and economic growth—over which regulators and utilities do not have direct control. This produces substantial uncertainty about important outcomes such as resource needs, rates, and emissions. Moreover, the costs and benefits of alternative resource strategies often differ as external factors vary. Hence, potential resource strategies must be evaluated under a range of market conditions. Simply setting each external (exogenous) factor to a single most likely value seldom provides insight into how strategies might perform under alternative market conditions. For this IRP, DEEP analyzed uncertainty by constructing scenarios, which we call "Futures" to distinguish from "Resource Scenarios," which are evaluated in the next section. The Futures are based on different natural gas prices and the relative amounts of supply and demand, while holding all other variables at their Base Case values.[36] With respect to supply and demand, the "Tight Supply" future incorporates ISO-NE's high economic growth load forecast (1,150 MW higher by 2020), and does not allow active demand response to adjust to capacity price changes. The Tight Supply future also assumes Boston's local resource adequacy problems are solved with transmission instead of adding internal resources. The "Abundant Supply" future incorporates ISO-NE's low economic growth load forecast (1,150 MW lower by 2020) and assumes that the Vermont Yankee nuclear plant remains in service during the study period. These two Futures thus span a large range of circumstances, covering any number of unanticipated changes that could have similar effects on the regional supply-demand balance, such as new imports of Canadian hydropower, changes in retirements, imports, demand response, and new capacity. They are useful for testing the robustness of alternative Resource Scenarios against a range of very different pressures on resource adequacy.

With respect to natural gas prices, the futures reflect the fact that natural gas price uncertainty directly affects electricity price projections. In developing the high and low commodity price cases, DEEP evaluated several factors including available high and low natural gas price forecasts from the U.S. Energy Information Agency (EIA), Wood Mackenzie, implied volatility from natural gas options prices, and historical "forecast errors" derived from comparing historic projections to realized gas prices. Considering all of the available data, it was determined that a high/low range relative to the Base Case commodity price forecast of roughly +60% to -40% captured a reasonable range of long-term natural gas prices suitable for planning purposes. The resulting price trajectories are shown in Figure 17, which also includes historical prices for comparison purposes. Figure 17 does not show transportation basis differentials or LDC charges, which are assumed to be identical to those in the Base Case.

In developing these natural gas price futures, elasticities of demand were applied to account for customers' likely responses to large, long-term natural gas price-induced changes in electricity prices.[37] A long-term elasticity of *energy* demand of -35% reduces energy consumption in the High Gas future by 13.4 terawatt-hours (TWh) in 2015 (10.0%) and by 14.4 TWh in 2022 (10.2%). It increases load in the Low Gas future by 8.9 TWh in 2015 (6.7%) and by 9.6 TWh in 2022 (6.8%). A long-term elasticity of *peak* demand of -17.5% reduces peak load in the High Gas future by 1,400 MW in 2015 (5.0%) and by 1,500 MW in 2022 (5.1%). It increases peak load in the Low Gas future by 900 MW in 2015 (3.3%) and by 1,000 MW in 2022 (3.4%).

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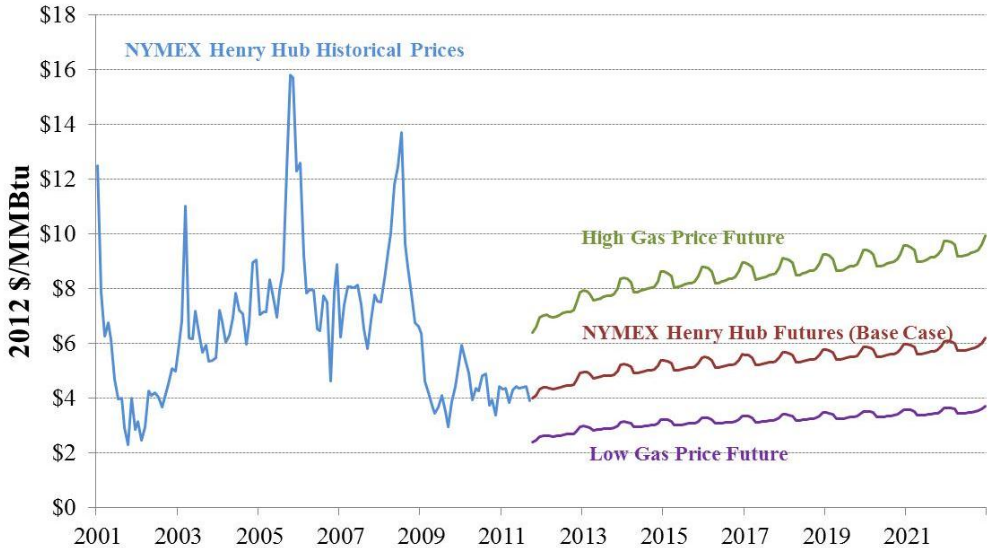
[36] Varying the Cost of New Entry was also considered and analyzed, but not used to construct an alternative Future because it had only a small effect on the outcomes.

[37] Elasticity is a measure of quantity response to price changes expressed as a quotient of percentage changes over a given time period. For example, if price increases by 1% and quantity demanded falls by 0.5%, then the elasticity of demand is -50% (-0.5/1).

Figure 17
Natural Gas Price Trajectories at Henry Hub



B. Costs and Emissions under Alternative Futures

The four alternative Futures described above were evaluated using the same modeling system used to develop the Base Case. Cost and emissions metrics are shown in Figure 18 through Figure 26, below. Some of the most salient observations from these figures are as follows:

- *Resource Adequacy*. Whereas new generation entry is not found to be economic for meeting the region's Net Installed Capacity Requirement in the Base Case until 2022, economic entry could occur in 2018 in the Tight Supply future, and 2019 in the Low Gas future as a consequence of higher load growth. The resulting range in capacity prices is shown in Figure 18. In all Futures, new generation is not necessary in Connecticut specifically in order to meet the Local Sourcing Requirement.

  As noted in Section IV, subsection A, the IRP assumes all four components of the NEEWS transmission project are constructed, increasing the Connecticut import limit to 1,100 MW and incorporating the Lake Road generating facility into Connecticut. In the event that the Interstate and Central Connecticut components of NEEWS were not constructed, Connecticut would still have adequate local resources to maintain reliability even in the Futures with higher load. For example, in the Low Gas future, higher projected capacity prices prevent some generation retirements and attrition of demand response, which offsets the higher load.

- *Costs and Rates*. The High Gas future has higher rates and the Low Gas future has lower rates than the Base Case primarily because of differences in wholesale energy prices shown in Figure 19. However, cost impacts are partially mitigated by demand elasticity effects, as shown by the smaller variation in the costs in Figure 20 compared to the rates. Costs and rates are also lower in the Abundant Supply future. Note that the rate increases over time are greater than the uncertainty across Futures in any particular year, as shown in Figure 20.

- *Generation*. As load varies across the Futures, most of the variation in generation is projected to occur in gas-fired units. Little dispatch switching occurs between fuels, except in the High Gas future, where coal generation increases at the expense of natural gas. In all of the Futures, the old, high-emitting oil-fired steam units would not generate at significant levels, as shown in Figure 25 and Figure 26.

- *Emissions*. The Futures with higher load (Tight Supply and Low Gas) have higher emissions, except High Gas, which has higher SO_2 and NOx emissions, as shown in Figure 21, Figure 22, Figure 23, and Figure 24. The relative emissions levels across cases are driven by a number of factors. For example, in the Abundant Supply future, emissions would decrease from 2015 to 2017 because the low load and presence of Vermont Yankee cause many retirements when the capacity price floor expires, including coal retirements. In the Tight Supply future, CO_2 emissions decrease from 2017 to 2022 because of the addition of 2,100 MW efficient combined-cycle plants. NOx is higher than in the High Gas future because high-emitting units are needed to meet a much higher peak load. In the Low Gas future, High Energy Demand Day NOx is higher than in the High Gas future because peak load is much higher.

Figure 18. Capacity Prices in New England (2012 $/kW-Year)

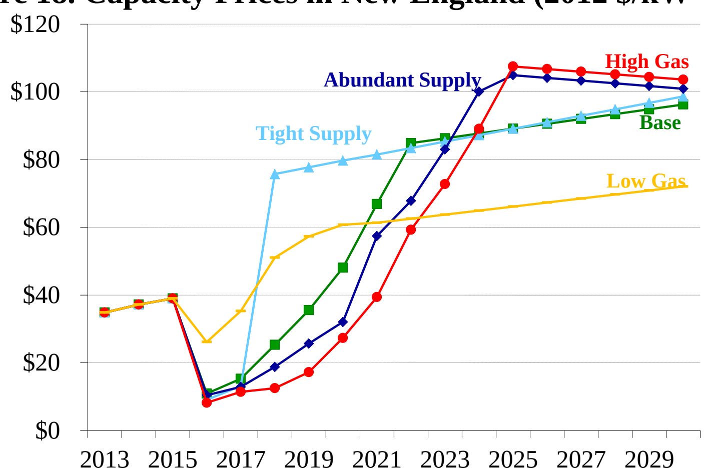


Figure 19. Annual Average Energy Prices in Connecticut (2012 \$/MWh)

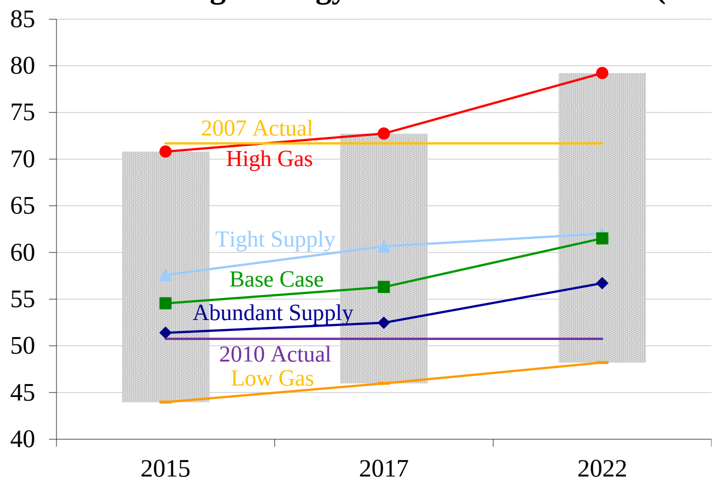


Figure 20. Connecticut Customers' Power Supply-Related Costs
(Includes GSC costs, EE charges, and Transmission charges associated with remote renewable generation)

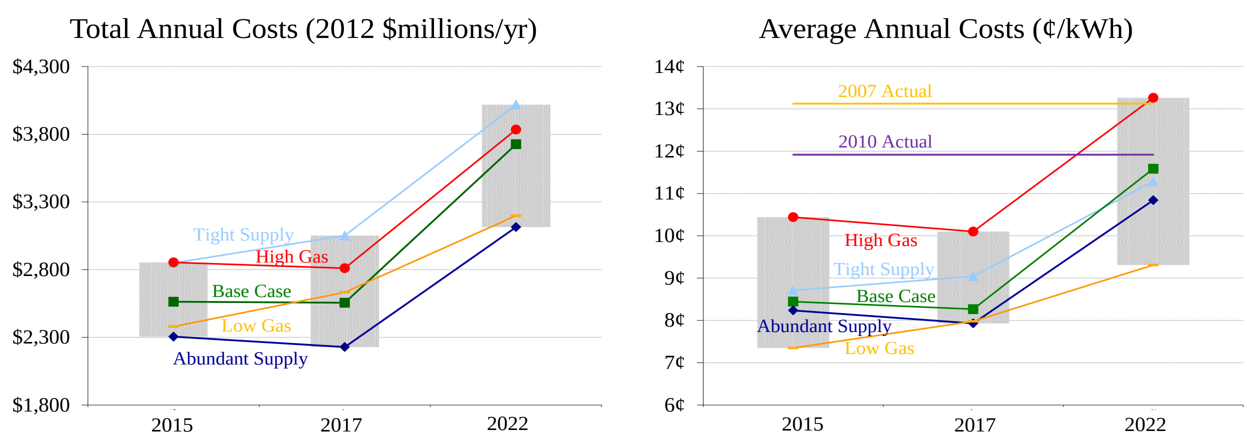


Figure 21. Annual CO_2 Emissions

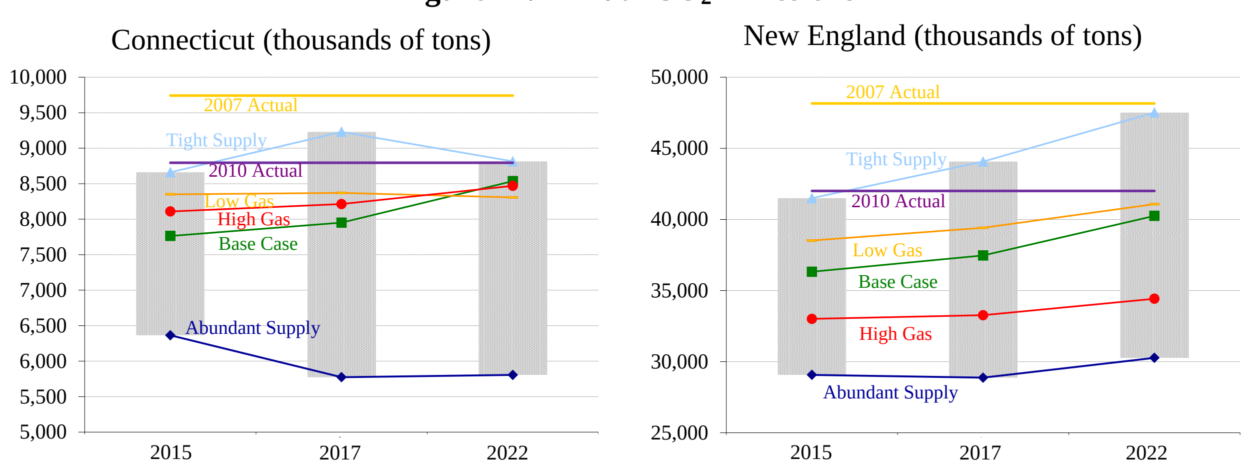


Figure 22. Annual SO_2 Emissions

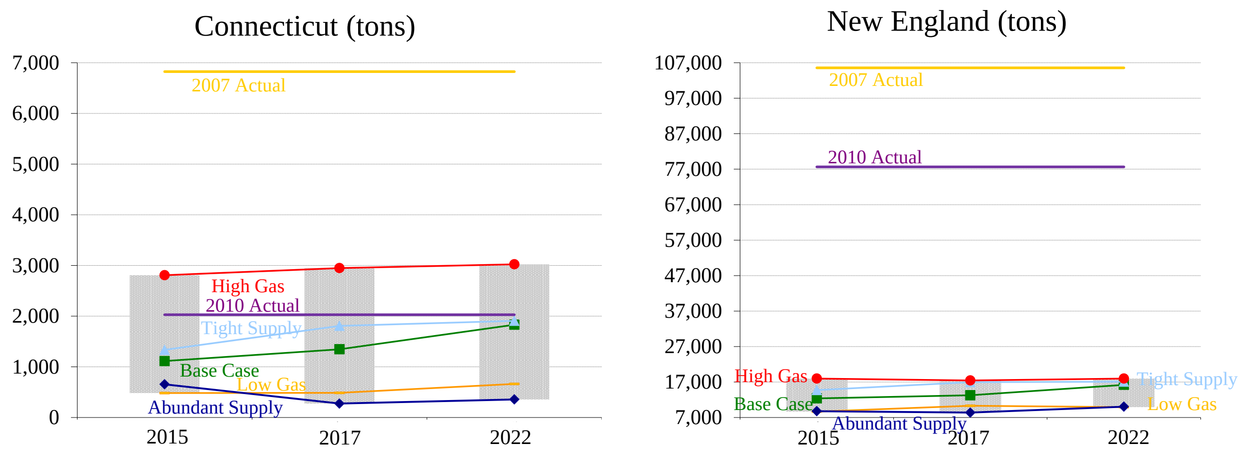


Figure 23. Annual NO_X Emissions

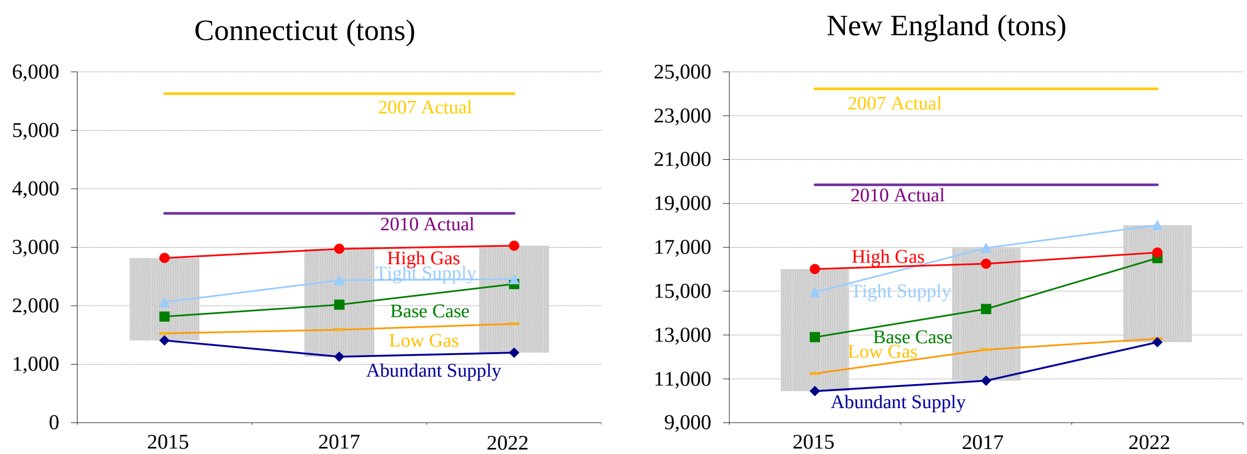


Figure 24
Connecticut HEDD NOx Emissions on Each of 10 HEDD Days (Daily Tons)

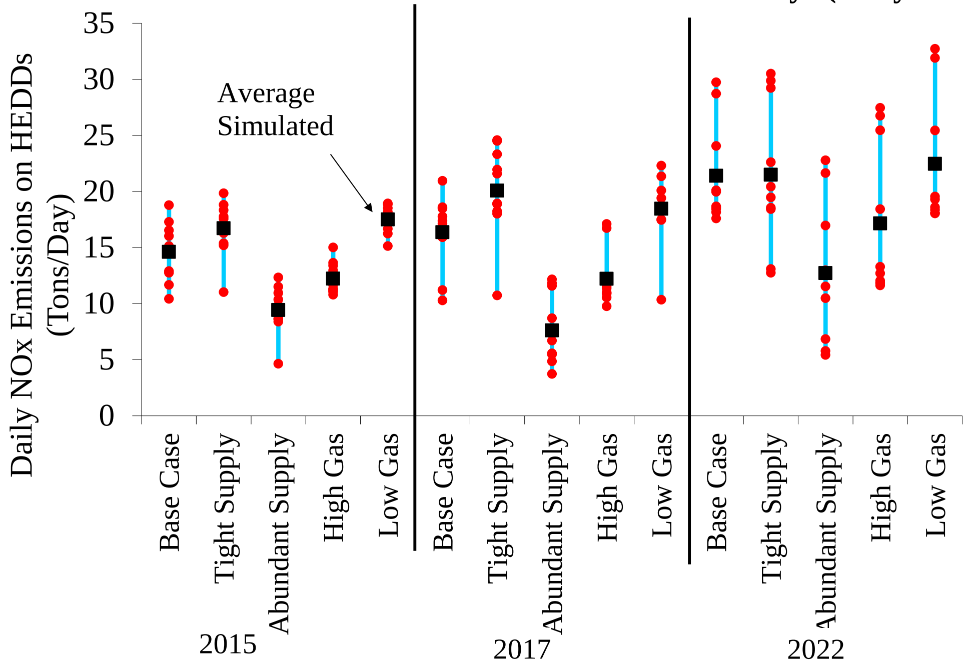


Figure 25
Connecticut Generation by Fuel Type (TWh)

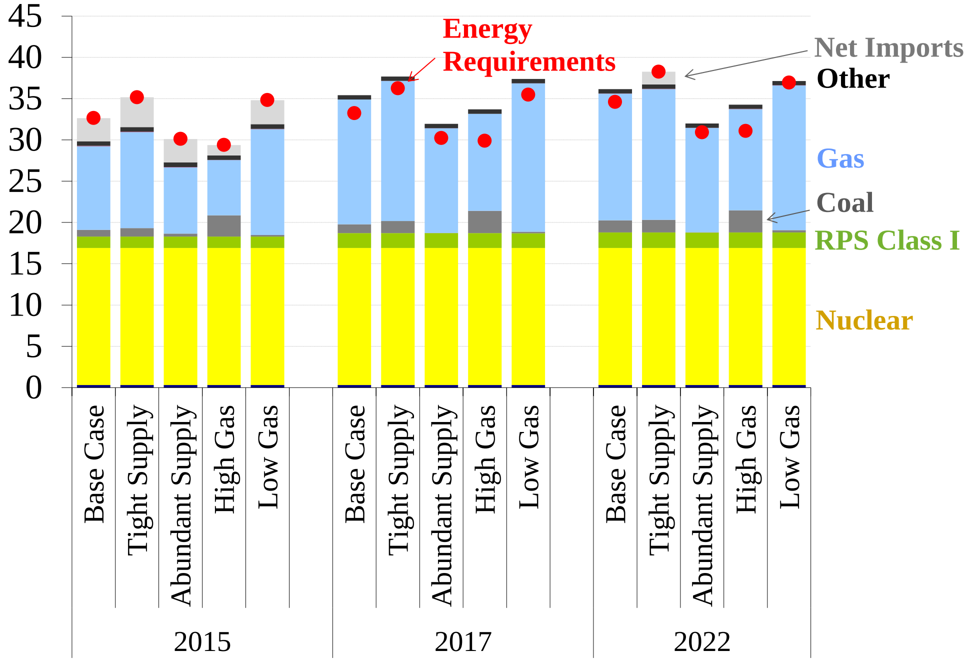
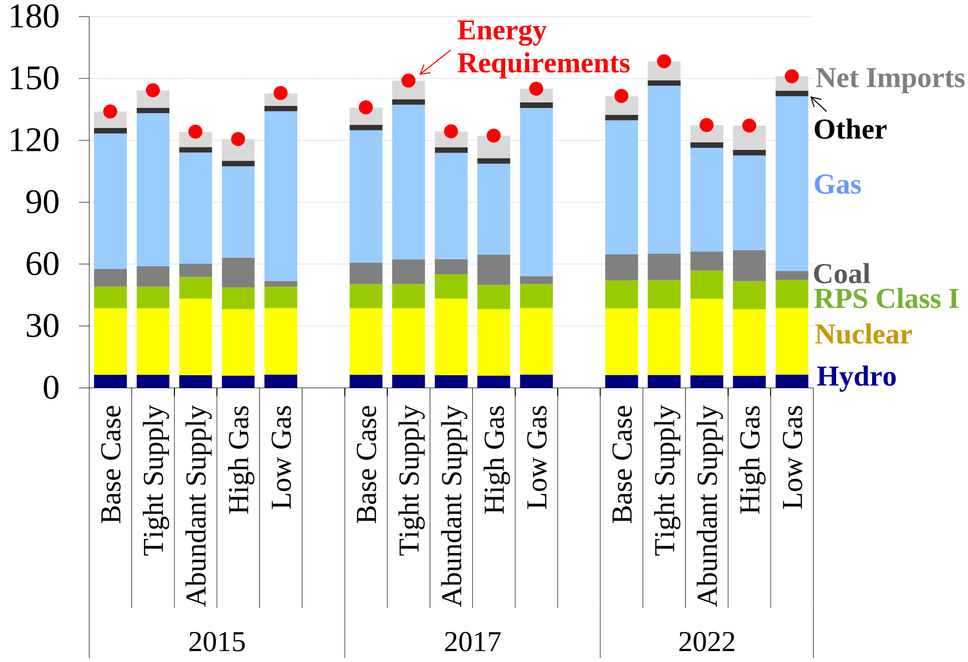


Figure 26
New England Generation by Fuel Type (TWh)



VI. EVALUATION OF RESOURCE SCENARIOS AND PLAN FOR SECURING RESOURCES

This section of the IRP introduces a plan for securing energy resources to minimize the cost to Connecticut customers over time and maximize consumer benefits consistent with the state's environmental goals and standards. This plan is based on the analysis of projected future electricity supply and demand, discussed above, as well as several resource scenarios evaluated for this IRP. It addresses opportunities in four key areas: promoting more energy efficiency through various policy approaches, meeting and/or redefining the RPS standards in various ways, fostering the development of new transmission, and facilitating the entry of new generation.[38] In developing this plan, DEEP tested several possible courses of action as "Resource Scenarios," acknowledging the fact that the State cannot fully control all of the factors examined, even if it can influence them. The Resource Scenarios evaluated in this IRP are defined as follows:

- *Expanded Energy Efficiency.* While the Base Case assumes continuation of energy efficiency programs at current levels, DEEP evaluated an Expanded Energy Efficiency resource scenario that nearly triples that amount of energy savings over the next decade. The opportunities for increased efficiency and

[38] Procurement and risk management strategies can also affect customer rates, but they are not considered here because Public Act 11-80 addresses procurement outside of the IRP.

the costs of achieving them are based on the Potential Study commissioned by the Energy Conservation Management Board (ECMB), dated April 2010.

- *RPS Scenarios.* DEEP evaluated the effects of maintaining the existing Class I RPS requirements. Acknowledging current uncertainty about how the RPS requirements could be met, DEEP examined three levels of Class I development: a Low Case, a Base Case, and a Full Renewables Buildout.
- *New Cost of Service (COS) Generation.* This scenario assumes the development of one new, efficient 656 MW gas-fired combined-cycle plant in Connecticut in 2017 (for $929/kW cost in 2012 dollars, excluding interest during construction), backed by power purchase agreements or other support from Connecticut customers. DEEP analyzed this scenario in order to asses the value to Connecticut customers of paying the full cost of new conventional generation and receiving its full market value, and doing so before such a resource would have been developed by merchant developers.

The subsections below describe the Resource Scenarios and their impacts on costs, rates, emissions, and jobs. Resource scenario evaluations are presented here for the Base future but were also evaluated across alternative futures, the results of which are included in Appendix A (Detailed Tables).

A. Expanded Energy Efficiency

To identify opportunities for securing Connecticut's energy resource needs through energy efficiency, DEEP tested an Expanded Energy Efficiency resource scenario based on the "Potential Study" sponsored by the Connecticut Energy Conservation Management Board (ECMB), conducted by KEMA Consulting, and filed in 2010.[39] The Potential Study estimates the savings that could be achieved based on a detailed, bottom-up analysis of hundreds of available energy conservation measures in each customer sector, and then applies a benefit-cost test to each measure to estimate an economic potential. Most of the measures are based on programs already being implemented by the electric distribution companies. Many of the measures evaluated in the Potential Study would involve significantly expanding the more innovative parts of existing programs, such as offering technical training to commercial customers on more efficient practices.

Based on the KEMA Potential Study estimates, the Expanded Energy Efficiency resource scenario estimates maximum cost-effective savings from energy efficiency programs over an 11-year implementation schedule from 2012 through 2022, as shown in Figure 27.[40] The Expanded Energy Efficiency scenario estimates that by expanding current efficiency savings to the maximum cost-effective level each year from 2012-2022, the resulting achievable, cost-effective savings will exceed Base Case energy efficiency savings by $534 million annually by 2022.These savings will exceed Base Case Energy Efficiency program savings by 1,071 MW

[39] The ECMB has since been renamed the Energy Efficiency Board.

[40] The reason the annual incremental savings from the Expanded Energy Efficiency scenario appear lower in the initial years is that the Base Case Energy Efficiency savings against which it is measured were assumed to decline over time.

(annual peak), and 4,339 GWh (annual energy) by 2022.[41] This finding is the basis for the Expanded Energy Efficiency scenario DEEP utilized in this IRP. Because each program measure would save energy over the entire multi-year life the equipment is installed, the savings from each year's measures would accumulate on top of prior years' savings as the electricity-using capital stock becomes increasingly efficient.

According to DEEP's model estimates, the annual cost of achieving this higher level of energy efficiency is $243 million more than the Base Case, comprising an incremental $105 million program budget, and an incremental $138 million in increased out-of-pocket spending by program participants to pay for their share of the efficiency measures.[42] The total implementation unit cost per kWh saved under the Expanded Energy Efficiency scenario is assumed to be similar to that in the Base Case. However, the participant is assumed to pay a larger share of total costs (i.e., receive lower program incentives than in the Base Case). This reflects an assumed expansion in the availability of financing over time, such as through the programs being developed by the Connecticut Clean Energy Finance and Investment Authority (CEFIA). If the program incentives were similar to those in the Base Case, the incremental rate increases would have to be 0.2 to 0.3 ¢/kWh higher.

Figure 27 shows the incremental savings and ratepayer program costs in the Expanded Energy Efficiency scenario relative to the Base Case. The $138 million in annual participant costs is not included in the table. These costs and savings are the quantities that are analyzed below in our economic evaluation of the Expanded Energy Efficiency scenario compared to energy efficiency assumed in the Base Case.

Figure 27.
Incremental Savings and Ratepayer Costs of Expanded Energy Efficiency
(Incremental to Base Case Energy Efficiency)

		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Annual Savings from Just This Year's Incremental Measures	*(GWh)*	366	377	383	388	392	397	401	407	408	409	411
Annual Savings from the Cumulative Effect of All Incremental Measures to Date	***(GWh)***	**366**	**743**	**1,126**	**1,515**	**1,906**	**2,303**	**2,704**	**3,111**	**3,518**	**3,928**	**4,339**
Annual Savings from Just This Year's Incremental Measures	*(MW)*	95	96	97	97	97	98	98	98	98	98	99
Annual Savings from the Cumulative Effect of All Incremental Measures to Date	***(MW)***	**95**	**191**	**288**	**385**	**482**	**579**	**677**	**776**	**874**	**972**	**1,071**
Annual Incremental Utility Budget	***($Mil)***	**105**	**107**	**107**	**107**	**106**	**106**	**106**	**106**	**106**	**106**	**106**

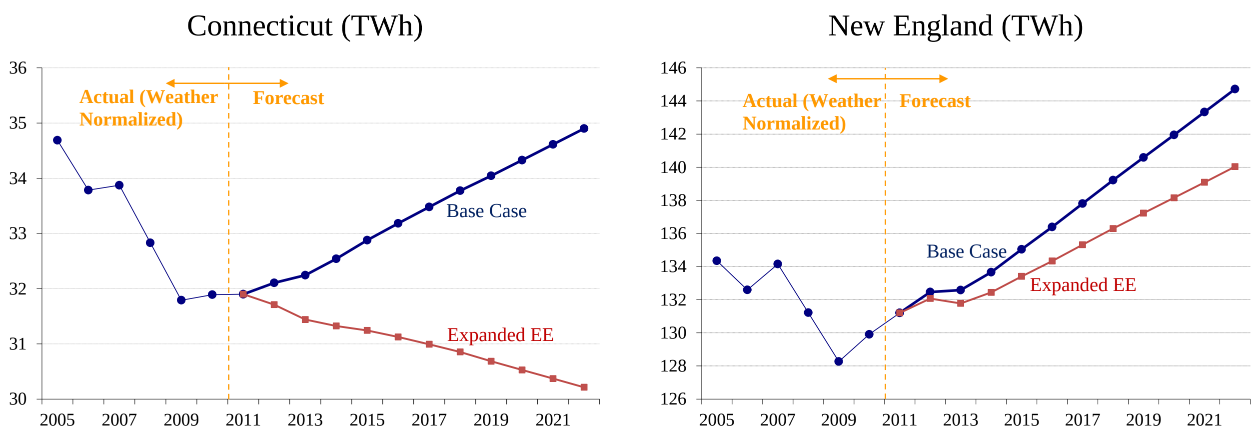
Implementing the Expanded Energy Efficiency scenario would support a growing economy that uses less energy both per unit of output and in absolute terms. Figure 28 shows that realized energy consumption in Connecticut would continually decline by about 0.4% per year net of the

41 These savings are quantified in the Potential Study's "Program Achievable Potential" scenario. The Potential Study reports 6,616 GWh of total program savings in the Program Achievable Potential, but only 4,339 is incremental to 2,277 GWh of program savings in the Base Case (with the "absolute" savings in each case measured relative to having no programs). Both the Base Case and the Expanded Energy Efficiency cases are assumed to have the same amounts of naturally-occurring energy efficiency and compliance with existing or planned codes and standards already implicitly embedded in the load forecast.

42 The annual cost of implementing the Expanded Energy Efficiency scenario is $206 million in program costs and $192 million in program participant out-of-pocket costs, which is $105 million and $138 million more, respectively, than the $101 million in program costs and $54 million in program participant costs in the Base Case.

effects of projected economic growth.[43] Relative to the base case, the Expanded Energy Efficiency scenario and would result in 4,339 GWh savings in 2022 from the cumulative effect of all incremental measures to date.[44] This projection of lower electric sales highlights the need to consider new business models for utilities that enable them continue making adequate returns in the face of declining sales from successful programs. DEEP will analyze alternative business models in order to develop recommendations for different rate structures that would achieve this goal, including: decoupling the distribution revenues from the volume of sales and reassessing shareholder incentives for successfully achieving energy efficiency savings. DEEP and the Energy Efficiency Board (EEB) will develop performance metrics for the programs and will call on the EEB to implement them.

Figure 28.
Effect of Expanded Energy Efficiency on the Energy Forecast



43 This projected decline rate does not account for the possibility that customers might engage in more energy-consuming activities when their equipment becomes more efficient—the so-called “rebound” and “snap-back” effects. Such effects would offset some of the projected savings.

44 In order to isolate the impacts of Connecticut investing in Expanded Energy Efficiency, utility programs in the rest of ISO-NE were assumed to remain the same as those used in the Base Case.

EXPANDED ENERGY EFFICIENCY — THE BASICS

What is "energy efficiency"?

Energy efficiency refers to using less energy to achieve the same level of service. For instance, installing efficient lighting in homes and businesses results in the same illumination while drawing less energy from the grid. Insulating a home allows one to maintain a given temperature by using less heating or cooling energy.

Why are energy efficiency programs needed?

Energy efficiency is implemented partly through end-users' own initiatives and partly through codes and standards. However, this is typically not enough to achieve all possible cost-effective energy efficiency due to various well-known barriers: poor customer information about energy efficiency; split incentives between building developers, owners, and tenants; lack of access to capital; and an inability of the individual customer to capture all of the benefits associated with reduced system transmission and distribution investment needs, reduced emissions, and increased energy security. Energy efficiency programs are intended to help overcome such barriers.

What do energy efficiency programs do?

Programs are designed to help customers install more efficient devices and adopt more efficient practices. In both residential and commercial sectors, lighting and cooling end-uses are the primary targets for improvement. In the industrial sector, motors and process heating are widely targeted end-uses. Some examples of the kinds of programs to capture these opportunities include:

- *Energy audits*. Typically, an authorized contractor performs an energy assessment for homes and businesses. They make on-the-spot improvements and, depending on customer's eligibility, provide exclusive money saving rebates on appliances, HVAC systems and insulation.
- *Equipment incentives*. Residential customers receive discounts and rebates on efficient light bulbs and appliances (*e.g.*, refrigerators, freezers, and dishwashers). For commercial customers, there are incentives to bridge the gap between the standard and more efficient lighting, air conditioners, refrigeration, and other kinds of equipment.
- *Financing programs*. Programs may offer customers low-interest loans and financing for energy efficiency improvements, often repaid through extra charges on the individual customers' bills.

What is the process for developing and approving and funding programs?

Each year, the Electric Distribution Companies prepare Conservation and Load Management plans with the advice and assistance of the Connecticut Energy Efficiency Board (chaired by the DEEP Commissioner) and its consultants. To the extent that the programs and requested budgets are approved, the Electric Distribution Companies administer the programs and recover the costs primarily through a special component of customer rates.

How much energy efficiency has Connecticut accomplished already?

Connecticut has been actively implementing energy efficiency programs for many years now. Connecticut's successful record in implementing programs and policies is manifested in the rankings of American Council for an Energy Efficient Economy (ACEEE). ACEEE evaluates each state based on its energy efficiency program spending, energy savings, targets, development of incentives, and removal of barriers (as well as policies, initiatives, *etc.*). According to ACEEE's 2011 State Energy Efficiency Scorecard, Connecticut remained tied for 8th with Minnesota but improved its total score by 5 points from 2010. This IRP examines whether Connecticut should pursue energy efficiency more aggressively.

Evaluation of Expanded Energy Efficiency Resource Scenario

The modeling system described in Figure 3 estimates the effects of resource scenarios on costs, rates, emissions, and in-state jobs. DEEP's analysis of the incremental savings and costs of the Expanded Energy Efficiency scenario revealed substantial benefits in all of these categories relative to the Base Case. As Figure 29 shows, the net cost savings appear modest or negative initially, but then become very substantial. This figure depicts the annual incremental level of program and participant costs in the red bars, which are constant for the three years shown (2015, 2017, and 2022).[45] The green bars indicate the annual incremental gross savings, shown as an offset to the costs. The clear bar indicates net costs if it is above the zero dollar axis and net benefits or savings if it is below the zero dollar axis. Benefits multiply over time because efficiency measures save energy for many years (12 years, on average), and each year's measures build on the measures implemented in prior years.

It is important to clarify several points related to the Expanded Energy Efficiency scenario. First, in 2017, the scenario predicts gross energy savings of approximately $238 million per year compared to the Base Case, a figure which appears to be less than the $243 million incremental costs. However, such a comparison does not recognize the multi-year benefits of the measures.

By 2022, DEEP projects that the Expanded Energy Efficiency scenario would save customers $778 million per year in energy, capacity, and RPS costs compared to the Base Case. At an annual incremental cost of $105 million in program costs and $138 million in participant out-of-pocket costs, customers' annual net savings would be $534 million. The $778 million gross savings can be explained in terms of quantity and price components:

- $425 million of the savings is the direct effect of consuming smaller quantities of costly commodities: $329 million less energy consumed, $56 million less capacity costs incurred, and $40 million less Alternative Compliance Payments. These estimates are derived by multiplying the change in quantity by the original (Base Case) prices.
- $350 million of the customer savings reflects reductions in market prices that would occur in 2022, brought about by lower demands for energy and capacity. $87 million of the savings derives from a $2.9 per MWh reduction in average energy prices, and $263 million in savings results from a $2.4 per kW-month reduction in capacity prices. The capacity price impact is so large because the peak load reduction from energy efficiency forestalls the need for new generation and defers the rise in capacity prices to a level needed to attract new generation into the market.[46]

In subsequent years, under the Expanded Energy Efficiency scenario, customers would continue to save money from the more efficient equipment installed in their homes and businesses. The gross savings would continue until the end of the measure lives (about 12 years on average) even

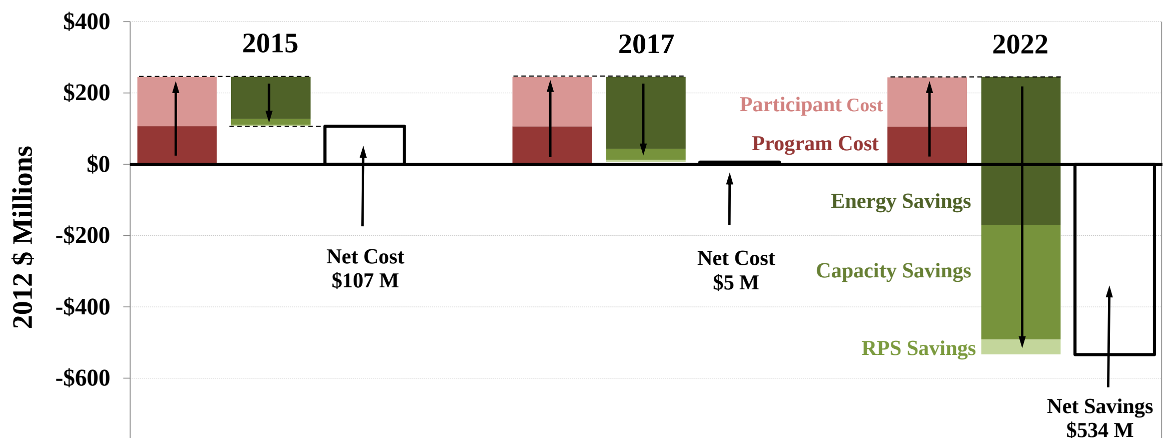
45 Alternatively, participant costs could be lower initially and higher in later years if some of the measure costs are financed, as contemplated in the Expanded Energy Efficiency scenario.

46 In the capacity market model, energy efficiency was modeled as a supply-side resource, not a demand reduction, consistent with how energy efficiency participates in ISO-NE's forward capacity auctions.

if no further measures were undertaken.[47] However, it is likely that programs would continue as old measures reach the end of their useful life and as new technologies and practices provide opportunities for new savings not yet envisioned in the Potential Study.

Although savings from energy efficiency measures last several years, the price reduction benefits would be in effect only temporarily until the electric supply side of the market adjusts. Because every dollar customers save due to reduced prices means that suppliers are paid a dollar less for the same product, the Expanded Energy Efficiency scenario may cause suppliers to retire more capacity, delay the construction of new generation, and/or offer capacity into the capacity auction at higher prices. DEEP's IRP modeling system analysis takes these effects into account, at least through 2022. The Expanded Energy Efficiency scenario is projected to cause 547 MW more retirements in 2016, and to delay the entry of new combined-cycle generation from 2022 to 2025 (with 714 MW less in 2025). Thus, the price effects would be expected to significantly diminish after 2022, and even earlier in the Tight Supply and Low Gas futures that need new generation before 2022. Although the price reduction benefits are temporary, it is important to recognize that the customer net savings from Expanded Energy Efficiency are substantially positive even without including price impacts. The Expanded Energy Efficiency scenario would create $425 million in gross savings in 2022, at a cost of $243 million in incremental program and participant costs. The price impacts can be viewed as a supplemental but transient benefit obtained from facilitating the development of low-cost resources.

Figure 29
Incremental Annual Costs and Savings of Expanded Energy Efficiency
(Relative to the Base Case)



[47] Annual benefits might be less than those estimated in 2022 once the supply-demand balance reaches a long-term equilibrium, where generation supply adjusts and there is little wholesale price impact from changes in demand. However, the quantity effects would still apply, with customers benefiting from reduced purchases.

When customers save money on energy expenditures, they can spend that money on other goods and services, which has a major and widespread effect on the Connecticut economy. Based on macroeconomic modeling conducted by the Connecticut Department of Economic and Community Development for this IRP, each $100 million reduction in net customer energy costs is projected to support or create 780 in-state jobs (based on a weighted average of residential, commercial, and industrial sectors). Thus, the annual net savings of $534 million in 2022 would support 4,200 more in-state jobs than in the Base Case for as long as the savings persist. In addition, implementation of the Expanded Energy Efficiency scenario would add 1,500 direct, indirect, and induced jobs. The direct jobs are associated with implementing measures, and the indirect and induced jobs are created in the rest of the economy for each year the program endures. Spending and jobs associated with in-state renewable investments would be reduced by 250, however, because load reductions would be expected to translate into fewer ACP payments. The net result is that the Expanded Energy Efficiency scenario would create 5,500 more in-state jobs per year than in the Base Case.

Overall customer costs, which are the product of rates and the quantity of energy services consumed, ultimately have a greater impact on the economy and on overall consumer well-being than do rates alone. Rates themselves may be important, however, to customers who participate less in energy efficiency programs. Under the Expanded Energy Efficiency scenario, 2017 rates would be 0.21 ¢/kWh higher than the Base Case. Overall rates in 2022 would decrease by 0.60 ¢/kWh, however, as a result of greater capacity and energy price effects.[48]

As explained in more detail in Appendix C, the Expanded Energy Efficiency program unit costs (expressed in $ per 1-yr kWh) are projected to be lower than in the Base Case. DEEP considered the cost and energy savings implications if these lower costs did not materialize and the program costs per kWh saved turned out to be the same as the average Base Case program costs over 11 years. In that case, achieving the full potential would require an additional 0.30 ¢/kWh increase in customer charges to support the programs. Alternatively, if the annual budget were limited to $206 million as assumed for the Expanded Energy Efficiency scenario, fewer savings would occur. The implied annual Expanded Energy Efficiency savings would be 428 GWh and 58 MW, instead of 601 GWh and 125 MW in the Expanded Energy Efficiency scenario described above. While this lower level of capacity savings would not necessitate replacement capacity over this time period (since there are no local or regional resource adequacy needs even in the Base Case), economic benefits would be lower. The reduced economic benefits may be very roughly proportional to the difference in GWh saved (relative to the Base Case) compared to the Expanded Energy Efficiency scenario. In 2022, for example, energy savings relative to the Base Case would be roughly $233 million (compared to $416 million in the Expanded Energy Efficiency scenario); capacity savings would be roughly $98 million (compared to $320 million

[48] The overall impact on rates is the combination of higher program costs offset wholly or in part by the lower generation service charges that reflect energy and capacity prices. In 2017, the Expanded Energy Efficiency scenario requires a 0.37 ¢/kWh increase in program funding, which is only partially offset by lower energy and capacity charges. This analysis does not quantify another related rate impact: reduced energy consumption would slightly increase the rate component necessary to recover fixed transmission and distribution costs; however some future transmission and distribution costs might also be avoided due to lower consumption, partially offsetting this effect.

in the Expanded Energy Efficiency scenario), and net savings would be approximately $191 million (compared to $534 million in the Expanded Energy Efficiency scenario)[49].

If the full cost-effective potential envisioned in the Expanded Energy Efficiency scenario is achieved, emissions would be significantly lower than in the Base Case. In Connecticut, emissions of NOx and SO_2 would decrease by more than 10%. In Connecticut and New England, CO_2 emissions decrease more than 5%. Notably, emissions would also be slightly lower in the Expanded Energy Efficiency scenario than those estimated under a Full Renewables Build-out scenario (described below), which would cost Connecticut customers considerably more than the Expanded Energy Efficiency resource scenario.

Conclusion: Expanded Energy Efficiency

Based on the analysis above, DEEP concludes that the analytical results provide strong support, in terms of widespread economic and environmental benefits, for achieving all cost-effective energy efficiency. To capture this opportunity, DEEP concludes that the state can cost-effectively achieve approximately 2% annual energy savings reduction in energy consumption by increasing the budget for Conservation and Load Management (C&LM) programs from $105 million annually under a business-as-usual budget to $206 million annually, and by initiating complementary measures such as providing low-cost financing, implementing more aggressive codes and standards, and motivating behavioral changes through information and training. Net of all program and participant costs, customers would save $534 million per year by 2022 compared to a business-as-usual base case. The savings arise from reduced consumption of energy, capacity, and renewable credits, and also from reductions in market prices resulting from expanding this low-cost resource.

Accordingly, the expansion of efficiency programs included in the 2012 Conservation and Load Management (C&LM) Plan submitted by the Energy Efficiency Board should be approved as part of a provisional longer-term plan to maintain that level of investment. The C&LM programs should be funded through charges on customers' bills, complemented by continued self-support from capacity credits earned in the forward capacity auctions, and with revenues from CO_2 allowance sales under the Regional Greenhouse Gas Initiative program. The charges on customers' bills can be expected to decline over time as the quantity and price of forward capacity market credits increase.[50]

Achieving the level of potential savings in the Expanded Energy Efficiency scenario will require more than just funding. Under the oversight of DEEP and the Energy Efficiency Board, utilities must continue to develop the innovative components of their programs, especially those components that advance energy conservation opportunities with relatively high non-cost barriers, such as training commercial customers in efficient operating practices. As appropriate,

[49] The emissions and job implications for this scenario can also be roughly estimated by proportionally scaling the Expanded EE scenario emissions and jobs using the difference in energy saved (relative to the Base Case) between the two scenarios. In 2022, the NO_X and SO_X emissions decrease by roughly 8% (compared to 10% in the Expanded EE scenario) and CO_2 emissions decrease by roughly 4% (compared to 5% in the Expanded EE scenario). Similarly, this new scenario would roughly yield 2,200 new in-state jobs (compared to 5,500 jobs in the Expanded EE Scenario).

[50] Another approach that could be considered for adjusting the time profile of rates to better match the time profile of benefits would be to make utility program costs a part of the rate base.

DEEP will propose the adoption of more aggressive codes and standards that can help achieve the desired results without any rate impact. DEEP will work with CEFIA to pursue opportunities that will enable participants to finance measure that will maximize efficiency savings by spreading the initial costs over time. DEEP will also evaluate rate structures that could be used to encourage efficiency while protecting all classes of consumers. These and other approaches are discussed further in Appendix C (Energy Efficiency).

The savings that can be achieved through the Expanded Energy Efficiency strategy will depend on several factors, including assumptions about equipment and practices that are in place today and the cost of improving them. Moreover, actually achieving the potential depends on the ability to enable and motivate participants to change and overcome non-cost barriers. Finally, the level of energy efficiency that is cost-effective, and the cost-effectiveness of particular measures, depends on market conditions. For example, under the High Gas future, saving 4,339 GWh per year under the Expanded Energy Efficiency resource scenario is worth $178 million more per year in 2022 than in the Base future. In the Low Gas future, Expanded Energy Efficiency is worth $403 million less than in the Base future in 2022, but $105 million more than in the Base future in 2017. This is because under the Expanded Energy Efficiency scenario, capacity prices would not rise sufficiently to attract new generation as long as low gas prices continue. In addition, overall customer costs in 2022 are expected to be lower in the Low Gas future compared with the Base Case, regardless of the impact of Expanded Energy Efficiency.

Energy efficiency is a flexible resource because it is pursued incrementally (although rapidly ramping programs up or down can be costly and disruptive). DEEP therefore concludes that energy efficiency programs should be ramped up beginning in 2012, on a trajectory to achieve all cost-effective program spending, but without locking in to a rigid plan. The details can be adjusted over time as updated information about the success of expanded programs becomes available, and about market conditions, technology costs, penetration levels and innovation, federal standards, and non-cost barriers to efficiency. Such information should be gathered through future Conservation and Load Management proceedings, market studies, and updated potential studies.

B. Renewable Portfolio Standard

The Connecticut Renewable Portfolio Standard (RPS) policy was instituted in 1998 in order to reduce reliance on fossil fuels and reduce emissions from the power sector. Since that time, Class I renewable development in New England has grown sufficiently to meet the region's current requirement, with renewable energy credit (REC) prices hovering around $20-$30/MWh during most of the recent year.[51] Looking forward, while the resource potential in the region remains high (particularly for wind power in northern New England), there are many uncertainties regarding the future pace of renewable development. First, substantial additional transmission would be needed to deliver and integrate large additional amounts of remote wind resources. Viable transmission options, their costs, transmission planning processes, and

[51] One renewable energy credit (REC) is created from one MWh of qualifying renewable electricity generated. Electric suppliers in New England can satisfy their RPS obligations by purchasing RECs or making alternative compliance payments. REC revenues supplement energy and capacity revenues received by generators. REC prices climbed to more than $50/MWh as of March 2012, in part owing to uncertainty surrounding Massachusetts' proposed biomass eligibility rules.

transmission cost allocation rules present regional challenges that Connecticut will work with others in the region to address. Second, the adverse financial conditions over the past three years have made it increasingly difficult for new renewable energy resources to secure funding. In addition, federal budgetary issues have compounded the perennial uncertainty regarding the future of federal production tax credits, after the current ones are set to expire at the end of 2012.

In light of Connecticut's continued commitment to reduce emissions from the power sector and diversify its fuel mix, this IRP evaluated and compared two potential future paths to achieving these objectives. The two alternative pathways are:

- **No Change to Existing Class I RPS Requirements.** There are significant uncertainties about the costs and achievability of the Class I requirement. To analyze these uncertainties, three levels of Class I compliance were evaluated: a Low Renewables case with very little additional Class I development; the Base Case, with more than 2,500 MW of projected renewable additions based on extrapolating observed development trends; and a Full Renewables Buildout case in which enough Class I resources (along with necessary transmission expansions) are developed to meet Class I demand in Connecticut and the rest of New England.
- **Modifying the Class I RPS Requirements to Allow Energy Efficiency or Large Hydro to Meet a Portion of the Goal.** Given the increasing costs and uncertainties around meeting Connecticut's expanding Class I RPS target, we evaluated the possibility of achieving the clean energy objectives of RPS Class I requirements with greater emphasis on energy efficiency and/or large, out-of-region hydroelectric resources to meet Connecticut's energy needs.

Evaluation of RPS Scenarios

No Change to Existing Class I RPS Requirements. Under the Base Case, DEEP projects that the region will be short of Class I requirements for year 2018 and beyond, with Connecticut paying high REC prices, Alternative Compliance Payments for substantial REC shortfalls, and a portion of new regional transmission costs as a consequence. From the standpoint of clean energy development, likely customer costs, and in-state job creation, this outcome falls short of the ideal. Under the Base Case, compliance with Class I would reach a cost of $445 million annually by 2022.

Figure 30 compares two alternative development paths for Class I compliance, showing the relative impact of achieving low and full Class I compliance. Under the Low Renewable scenarios, annual customer costs in 2022 are $365 million, which is $80 million lower than the Base Case, with similarly high REC prices and Alternative Compliance Payments but reduced transmission costs associated with reduced wind development. After accounting for the difference in energy and capacity costs (shown in Appendix A), the annual customer costs in 2022 under the Low Renewable scenarios are roughly $100 million lower than the Base Case. This potential scenario, however, represents a failure to achieve the objectives of the RPS, with customers still paying more than $250 million per year in Alternative Compliance Payments while receiving minimal environmental benefits.[52]

Figure 30. Alternative Renewable Market Outcomes

Scenario	Class I Demand *(GWh)*	Class I Supply *(GWh)*	REC/ACP Price *($/MWh)*	Class I RECs *($Mil)*	Class I ACPs *($Mil)*	Tx for RPS *($Mil)*	CT Renew. Prog. Net of Mrkt. Revs. *($Mil)*	Total RPS Costs *($Mil)*	Emissions Reduction
Full Class I Achieved	20,281	20,281	$17	$115	$0	$179	$92	$385	High
Base Case Class I Achieved	20,281	17,428	$45	$168	$130	$81	$67	$445	Medium
Low Class I Achieved	20,281	13,496	$45	$57	$257	$0	$51	$365	Low

Note: "CT Renew. Prog Net of Mrkt. Revs." reflect the annual payments needed to support in-state Class I programs (Project 150, residential solar PV, ZREC, LREC, and other Class I projects) net of energy, capacity and Class I market revenues.

52 The ACP revenues were assumed to fund rooftop photovoltaic installations, fuel cells, and other behind-the-meter projects that do not displace as much fossil generation as grid-connected renewables that create RECs.

RENEWABLE PORTFOLIO STANDARDS — THE BASICS

What are Renewable Portfolio Standards?

Renewable Portfolio Standards (RPS) are state-specific policies for requiring a certain portion of the electricity consumed to be sourced from renewable generation or low-emission resources. Connecticut's RPS requires electric suppliers to serve at least 20% of the state's retail load with new wind, solar, fuel cell, landfill gas, small hydro, and biomass resources (called "Class I"), 3% with existing renewable resources (called "Class II"), and 4% with combined heat and power or energy efficiency (called "Class III") by 2020. Maine, Massachusetts, New Hampshire, and Rhode Island also have similar Class I RPS requirements. Failure to meet the requirements results in Alternative Compliance Payment penalties, which Connecticut would use to fund in-state renewable programs.

What renewable resources does Connecticut have?

Although Connecticut has very limited in-state renewable energy resources, it has the potential to build some small-scale wind, solar, fuel cell, hydro and biomass projects. To date, Connecticut has relied on existing resources, largely located outside of Connecticut to meet its Class I RPS requirement. As the magnitude of the Class I requirement grows, Connecticut's purchase of RECs from outside resources will likely continue to increase.

What mechanisms does Connecticut use to develop in-state renewable energy?

Connecticut uses several approaches to support in-state development of Class I resources, including requiring utilities to enter into long-term contracts with projects located on the customer-side of the meter. A *Clean Energy Finance and Investment Authority* (CEFIA) has been established to promote investment in and commercialization of clean energy technologies.

What out-of-state resources are important to Connecticut?

Northern New England, especially Maine, is rich with wind resources. However, a large build-out of wind energy projects in Maine will require significant new transmission investments to integrate and balance that wind power onto the New England grid. Numerous transmission projects have been proposed to help meet regional Class I RPS requirements.

How is renewable energy paid for?

In addition to federal tax credits that help offset the cost of qualified renewable energy projects, producers receive renewable energy credits, "RECs," for every MWh of renewable or clean energy produced. Electric suppliers that need the RECs to satisfy their RPS requirements will buy them from producers at a market price. These payments help producers earn revenues in addition to those from selling the associated power. Connecticut also has several special programs to provide additional financial support for developing in-state projects for which the value of RECs and power alone would be insufficient.

The Full Renewable Buildout scenario shows better results, but would rely on coordinated and timely investment in transmission to support the development of a significant amount of wind power in northern New England. In other words, achieving the Full Renewable Buildout scenario will depend on the favorable resolution of uncertainties around transmission build-out that are not within any single state's direct control. Under the Full Renewables scenario, the region would meet the existing Class I requirement, with REC prices set by the levels required to support the development of onshore wind, which are significantly lower than the Connecticut Alternative Compliance Payment. Transmission costs would be higher under the Full Renewable scenario than in the Base Case. Assuming 25% allocation to Connecticut (based on its load share in New England) however, these higher transmission costs would be more than offset by the reduced REC prices and the absence of Alternative Compliance Payments.

Overall, the total RPS-related costs in the Full Renewable Buildout scenario would be about $60 million less than in the Base Case. After accounting for market price impacts on energy and capacity, the customer costs would be about $160 million less than in the Base Case, with greater emissions reduction and greater positive employment effects due to lower customer bills than in the Base Case.

With respect to employment impacts, in the Full Renewables scenario, the development of remote generation and transmission would not support many jobs in Connecticut. However, in the Low Renewables scenario, the use of the annual Alternative Compliance Payments of almost $260 million to install in-state renewable projects would support approximately 800 jobs (including associated indirect and induced effects on the broader economy), plus an additional 800 jobs resulting from lower customer costs compared to the Base Case (mostly from not having to pay for as much transmission). The downside of the Low Renewables scenario is that it would still be costly without substantially achieving the environmental objectives of RPS.

By testing different levels of Class I development, these scenarios demonstrate that regional cooperation is critical to ensuring that the necessary transmission is developed, such that sufficient renewable resources can be developed in New England and environmental objectives can be achieved. If the necessary transmission and resources are not developed, Connecticut customers would likely face large Alternative Compliance Payments without fully achieving the RPS objectives.

Modifying the Class I RPS Requirements to Allow Energy Efficiency or Large Hydro to Meet a Portion of the Goal. If complying with Class I RPS requirements increases customer costs significantly, then Connecticut would explore new ways of meeting its clean energy targets. For example, if the region's transmission planning process fails to meet the region's needs for new transmission to access remote renewable resources, it may make sense to allow a broader set of clean resources to attain Connecticut's clean energy objectives. Potential clean energy resources could include new energy efficiency and large hydropower.

To illustrate the potential impacts of using other clean energy resources to meet the needs of Connecticut, we analyzed a policy that would allow up to one quarter of the current Class I requirement to be met through the additional energy efficiency developed under the Expanded Energy Efficiency. Under this policy, energy efficiency that qualifies for Class III RECs could be used to meet a portion of the Class I RPS requirements. However, the energy efficiency would not be paid as a Class I resource.

Allowing up to one quarter of the current Class I requirement to be met through Expanded Energy Efficiency would produce benefits relative to the Base Case. Allowing conservation to meet part of the Class I requirement would save customers $152 million annually by 2022 compared to the Expanded Energy Efficiency scenario. These savings are the result of reducing the quantity of Class I RECs purchased and Alternative Compliance Payments made, and also reducing the Class I REC price from a $45/MWh scarcity level (set by the Alternative Compliance Payment) to an $18/MWh market price set by the long-run marginal net cost of onshore wind.[53] Another possible means to reduce the Class I RPS costs would be to allow power from large hydroelectric facilities outside of New England to count towards a portion of the Class I RPS requirements.

Conclusions: Renewable Portfolio Standard

Based on the analysis in this IRP, DEEP anticipates a significant challenge ahead in meeting Connecticut's aggressive RPS targets at a reasonable cost. Connecticut, however, is currently meeting its Class I RPS goals and a shortage is not expected until around 2018 under Base Case assumptions. DEEP therefore believes it is not necessary to make any changes to the RPS at this time. DEEP does believe, that in the near term, policy choices must be made with respect to the Class II and Class III REC market to address concerns raised in this IRP.

DEEP has evaluated the costs and risks that Connecticut customers face in complying with the existing RPS Class I requirements. Based on our assessment of the potential environmental benefits and customer costs of different approaches, DEEP concludes that Connecticut must strive to meet the existing Class I RPS requirements by actively engaging in regional efforts to resolve transmission planning and cost allocation issues, to enable further development of the region's renewable resources and implement strategies to reduce costs. DEEP believes that mechanisms such as long-term contracts must be explored to encourage the development of low-cost renewable generation.

DEEP will continue to carefully monitor the progress in the region's renewable resource development. In the next six months, in accordance with Section 129 of Public Act 11-80, DEEP will examine RPS issues in more detail, including other ways to achieve the Class I requirements. This analysis will include using energy efficiency and large hydroelectric resources to meet a portion of the Class I RPS goals. Careful monitoring of overall progress will be important to ensure that efforts to meet the Class I RPS requirements do not unnecessarily increase customer costs in Connecticut. If it appears that complying with the existing Class I RPS requirements will become unnecessarily costly to customers without achieving important clean energy and economic development goals, then DEEP will make recommendations to modify the Class I market. DEEP will also explore whether a large Class I biomass project could improve RPS compliance while yielding benefits to ratepayers.

As part of this forthcoming analysis, DEEP will examine the issues facing in-state resource recovery facilities to develop a long-term plan to ensure that they are able to continue operations. Class II RPS requirements will be reassessed to provide a better supply/demand balance to create more meaningful Class II REC prices to support existing and new Class II projects. DEEP will reconsider whether the RPS provides sufficient incentives for Class II generators, or whether other options, such as purchase power arrangements, are necessary. In the interim, a short-term power purchase agreement may be necessary for some facilities until a longer-term plan can be implemented.

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[53] The lower Class I price does not save customers money on net for approximately 1,150 GWh of Class I RECs created by Connecticut-specific ZREC, LREC, Project 150 and Other Class I programs. Reductions in Class I revenues increase the amount of customer support that must be collected through special charges to fund these special programs.

Class III RPS requirements will be also reassessed in order for the state to continue to support combined heat and power and third-party sponsored energy efficiency through the RPS. Since utility-based energy efficiency programs are funded through the Conservation and Load Management program, the Class III Renewable Portfolio Standard could be revised to focus primarily on providing incentives to combined heat and power and third-party energy efficiency programs that do not have a dedicated source of funding. The actual target level and the associated Alternative Compliance Payment and price floor for the Class III RECs need to be reexamined in such a way that the revised policy provides an appropriate and adequate level of support for the resources desired.

C. New Cost-of-Service Generation

The New Cost-of-Service Generation Resource Scenario examines the value to Connecticut customers of building and "owning" a plant before such a resource would have been developed by merchant developers. To analyze this scenario, we assumed the development of a new efficient-scale 656 MW gas-fired combined-cycle plant in Connecticut in 2017, at an overnight cost (excluding interest during construction) of $929/kW (in 2012 dollars). Consistent with our assumptions for generic merchant entrants, we assumed $17/kW-year fixed operations and maintenance costs, but we departed from generic assumptions by using a relatively low 6.7% after-tax weighted-average cost of capital, reflecting the allocation of risk to customers. Customers would pay for the full capital cost plus fixed operating and maintenance costs, following a traditional regulated cost-of-service revenue requirements schedule over an assumed 30-year life of the plant, through the imposition of a non-bypassable charge. They would receive all of the plant's revenues, including any energy margins and capacity revenues.

This analysis did not evaluate a scenario in which capacity is needed but merchant generation is not forthcoming, and the states or ISO-NE solicit capacity as a backstop for meeting reliability needs. Such a scenario was not evaluated because our resource adequacy analysis did not identify a need for new generation over the study horizon. The exceptions are in the "Tight Supply" and "Low Gas" futures, where new generation becomes needed in 2018 in New England, although not in Connecticut specifically. Future IRPs should assess whether those futures are being realized or new generation is needed for any other reason, and whether the market is likely to fail to meet that need.

Evaluation of New Cost-of-Service Generation Resource Scenario

Building new generation always entails assuming risk, but sponsoring a new generation facility well ahead of likely market needs inflates these risks and using a cost-of-service cost recovery model shifts risk onto customers. In addition to the typical risk that any particular plant might not earn enough in the markets to cover its development cost (including a return on investment), recent capacity market rule changes raise the real possibility that a proposed new resource will not qualify for *any* capacity payments during its early years in operation. This likelihood arises from the implementation of the Minimum Offer Price Rule (MOPR), which is a new feature being added to Forward Capacity Markets in order to prevent and mitigate the exercise of buyer market power, i.e., artificially depressing the capacity price by flooding the market with uneconomic capacity.[54] The details regarding the rule and also the application of the rule to individual market offers have not yet been fully determined. Generally, new generation will have to offer into the forward capacity auction at a competitive (i.e., cost-reflective) price, as if it did not have a state-sponsored contract. A resource being introduced before it would be economic on a competitive basis might not clear the market and thus might not get paid for capacity.

In the most stringent case, the new cost-of-service generation unit that was examined in this scenario would not earn capacity revenues until at least 2023, at which time a new merchant unit also would be competitive. However, it is possible that the unit could clear the capacity market earlier if its lower financing costs are considered in determining its mitigated offer floor, or if it has low unit-specific construction costs. Instead of analyzing every possibility, we evaluated customer benefits under two divergent assumptions: 1) that the unit would receive no capacity revenue (i.e., not clear in the auction based on a relatively high minimum offer price floor) until 2023; and 2) the most optimistic assumption that the minimum offer price floor for this unit somehow would be low enough that the unit would clear the auction and receive capacity revenues immediately upon commencing operation in 2017.

[54] Federal Energy Regulatory Commission, "Order on Paper Hearing and Order on Rehearing," Issued April 13, 2011, 135 FERC ¶ 61,029, Docket No. ER10-787-000.

COST-OF-SERVICE GENERATION — THE BASICS

What is cost-of-service generation?

Most generation in New England is owned by independent power producers, who expect that revenues from wholesale markets including capacity and energy markets will exceed their operating costs and earn them a return on invested capital commensurate with the risks they take. Revenues based on future market prices can be highly variable (i.e., risky) and therefore investors demand relatively high returns. An alternative arrangement is possible, whereby a developer sells the power under a long-term contract with a state agency or utility, with the price of that power reflecting the all-in costs of building and operating the plant, net of all revenues received. The purchaser then recovers the power costs from customers. By guaranteeing a revenue stream that covers capital and net operating costs, the contract essentially shifts market risks and rewards to customers; revenue predictability reduces development risk and enables lower cost financing. These contracts mimic traditional "cost-of-service" regulation where utilities build power plants based on assurances that prudently-incurred costs (including reasonable payments to debt and equity) will be recovered in regulated rates.

How does cost-of-service generation fit into wholesale and retail markets?

Cost-of-service contracts enable the introduction of specific resources into the wholesale power market that private developers otherwise might not provide. These resources may be sought for reliability enhancements (capacity value or quick-start reserve capability); to meet fuel diversity or risk hedging objectives; or to foster particular technologies (solar, fuel cells). In restructured retail markets such as Connecticut, contractual terms and rate recovery details have to recognize that utilities do not own generation or have captive load to serve. The costs of such long-term contracts are typically recovered through non-bypassable charges that appear on all customer bills, regardless of their choice of retail energy supplier. Using non-bypassable charges spreads the costs across all customers and avoids the situation where cost recovery falls on specific suppliers who customers might drop because the charges (especially in the initial years of cost recovery) are above-market compared to other suppliers.

Does Connecticut have any cost of service generation or similar arrangements?

There are several examples of cost-of-service generation and other similar arrangements in Connecticut. Over the past few years, the state has sponsored the development of 506 MW of combustion turbine projects to help meet quick-start reserve requirements in Connecticut, through cost-of-service agreements. In other cases, the state has sponsored or required the use of long-term contracts coupled with non-bypassable customer surcharges — although none has used the cost-of-service model discussed here. For example, capacity from the Kleen project (a 620 MW combined cycle plant that began operating in 2011) is procured under a long-term contract, and long-term contracts support the development of specific in-state renewable projects under the Project 150 program.

For simplicity, Figure 31 shows the annual costs and direct benefits to customers only for the Base future with the more stringent Minimum Offer Price Rule capacity revenue assumption. The figure shows that regulated revenue requirements would be initially much higher than the energy margins the unit would receive, while capacity revenues are unavailable until 2023. When the capacity revenues appear in 2023, overall market revenues would exceed the assumed cost-of-service revenue requirements paid by the customer-owners, for two reasons: (1) capacity market revenues at that point would be assumed to be determined by a merchant generator, which has higher financing costs due to higher rates paid to debt and equity holders and a shorter amortization period; and (2) the cost-of-service revenue requirements would have declined with depreciation. However, the net benefits after 2023 would not outweigh the initial net costs in present value terms until 2035, as shown in the left half of Figure 33.

The overall value to customers appears more positive if energy price reduction benefits are included. Building an efficient combined-cycle plant in advance of the time of need reduces energy prices by $1.6 to $2.1/MWh between 2017 and 2022, until the capacity would have presumably been built anyway in 2023. Including the resulting $49–66 million of annual benefits suggests a more positive proposition for customers. On a cumulative NPV basis, it would still be more costly than doing nothing until 2022, as shown by the dotted curve in Figure 31.[55] These figures do not show the (slightly greater) value available if a lower minimum offer price is accepted and the unit clears earlier when capacity prices are still low. The results of this case and all others analyzed are shown in Appendix A (Detailed Tables).

The right half of Figure 32 shows the value of waiting to build the unit in 2020, closer to the time when New England will need capacity (although not in Connecticut specifically). The net cost is considerably lower compared to building in 2017, with six fewer years until breakeven on an NPV basis. Although there are also fewer years of energy price reductions between the time the plant is built and when a similar plant might have been built otherwise, the overall profile is still more favorable than building in 2017. In fact, including energy price reduction benefits (the dotted line) shows that the unit might break even on a cumulative NPV basis almost immediately upon operation in 2020.

Regarding emissions, building an efficient gas-fired plant in Connecticut would reduce New England emissions of NOx, SO_2, and CO_2. However, with the additional local generation, Connecticut's in-state NOx emissions would increase by several percent for the summer and annually, with a slight reduction in NOx emissions on High Energy Demand Days as the new plant displaces some less efficient, higher-emitting generation. The emissions savings could be greater if somehow the new generation plant could be part of a package agreement to close a high-emitting existing generator that otherwise would not retire.

Developing a 656 MW combined-cycle plant would create 2,700 jobs during the two-year construction period, followed by 100 ongoing jobs over the life of the plant. All jobs estimates include direct, indirect and induced effects of the project on in-state employment. Unlike the Expanded EE scenario, we have not quantified additional employment benefits associated with customers' energy savings because customer costs rates would be higher initially. With COS rates, Connecticut customers' estimated net savings would be only slightly positive by 2022, even when accounting for LMP impacts. Thereafter, estimated net savings would increase as COS rates decrease over time.

55 "Cumulative NPV" is defined as the sum of all prior year's cash flows, with each year's cash flows discounted to a 2017 value, and then expressed in 2012 real dollars.

Conclusion: New Cost-of-Service Generation

This analysis of resource adequacy needs indicates that new generation is not needed in New England until 2022 or later, and not needed specifically in Connecticut until much later. The economics of building cost-of-service generation ahead of need suggests some potential benefits, although nothing strongly positive. Given these findings, and barring any unforeseen circumstances that would necessitate an amendment to this IRP, DEEP concludes that no action should be taken until closer to a time of need. DEEP will reconsider in the next IRP (2014-2015) whether there is a need to sponsor new generation, based on updated information on market conditions at that time.

Figure 31
Annual Costs and Revenues of a 656 MW, $929/kW Cost-of-Service Combined-Cycle Plant
(2012 $Mil)

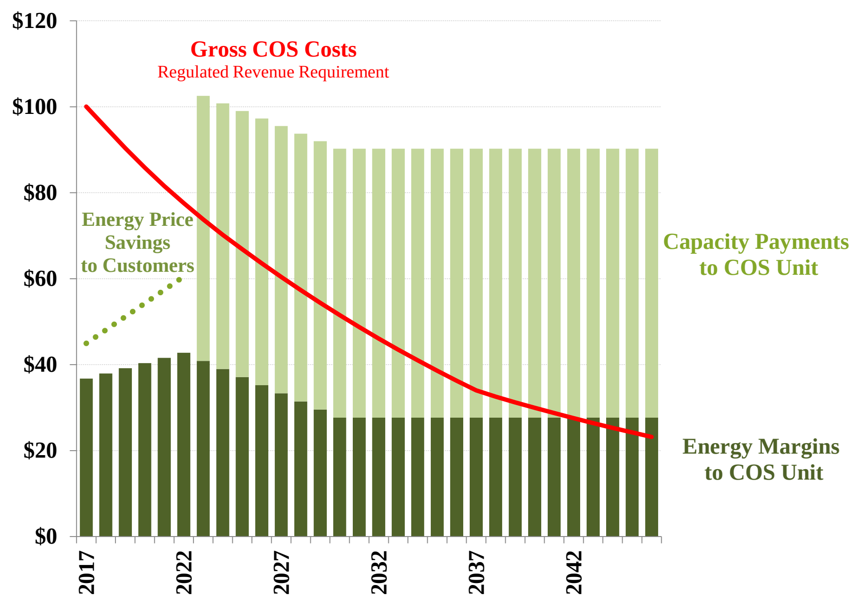
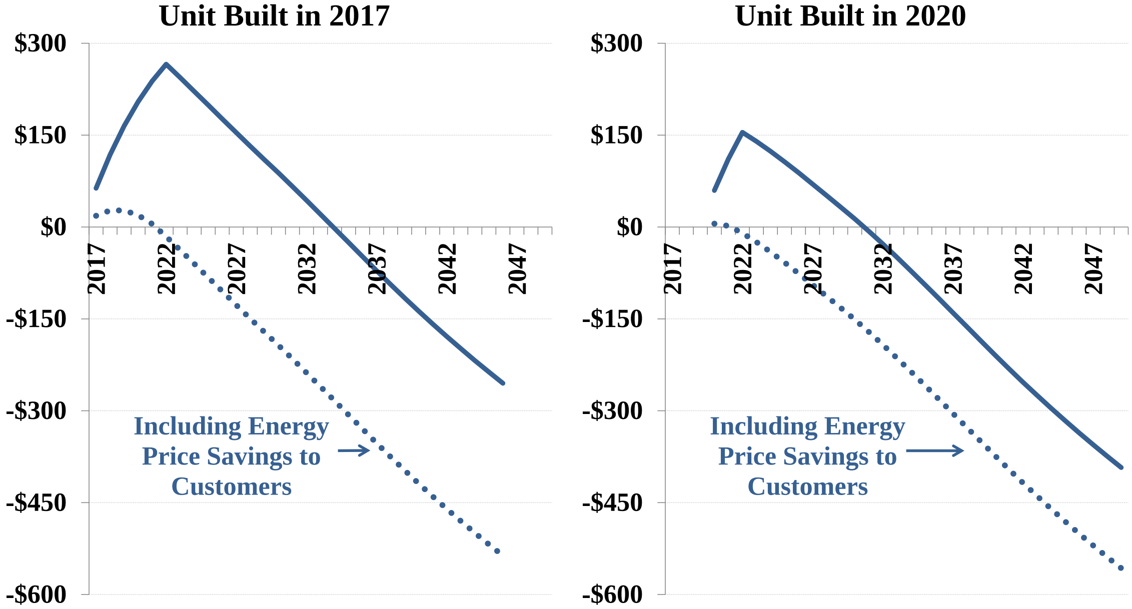


Figure 32
Cumulative NPV of the Costs of a COS Plant (2012 $Mil)



D. Transmission

Section 90 of PA 11-80 requires DEEP, as part of its development of the IRP, to consider Non-Transmission Alternatives (NTAs). Because there are no transmission enhancements to the Base Case being considered in this IRP, no NTAs were evaluated. Appendix G (Transmission Planning) does address the identification and evaluation of NTAs generally. As discussed there, ISO-NE is currently developing an NTA process, and the State of Connecticut should be engaged in that development. This will be especially important over the next year when the ISO will conduct a reliability needs analysis including consideration of NTAs for central Connecticut and Hartford.

Appendix G also describes identified transmission reliability needs and ongoing studies in Connecticut, particularly in southwest Connecticut and central Connecticut. It also summarizes emerging issues affecting transmission planning.

E. Emerging Technologies

For this IRP, DEEP assessed emerging technologies that may provide attractive energy resource options in the coming decade and beyond, even if they are not yet developed enough to play a major role in the current market. Five technologies of interest to stakeholders in Connecticut's resource planning process are: plug-in electric vehicles (PEVs), advanced metering infrastructure (AMI), energy storage, advanced waste-to-energy, and geothermal energy. For each technology, we identified current trends, the potential for the technology to play a role in Connecticut's portfolio of energy resource options in the coming decade and beyond, and state-level activities that could help enable further adoption. Findings and recommendations are explained in Appendix H (Emerging Technology) and summarized below.

Plug-in Electric Vehicles. Connecticut's Electric Vehicle Infrastructure Council and the Electric Distribution Companies collectively are preparing the state for rapid and seamless integration of Plug-in Electric Vehicles (PEVs) into the market. In 2011, the Electric Power Research Institute (EPRI) developed projections for Connecticut, which estimate that the new vehicle market penetration of PEVs may reach 7% by 2020 and 16% by 2030 under a medium market penetration scenario. Based on these current trends, the impacts on the generation system and peak demand should be manageable for Connecticut's Electric Distribution Companies, especially if the charging load can be managed with time-varying rates enabled by user-friendly charging technology. However, coincident charging may create problems for local distribution systems, especially if the PEVs cluster in certain locations. For these reasons, it is important that Connecticut adopt a proactive approach to the deployment of PEVs, and address near-term localized impacts. State initiatives and pilot programs should be used to provide insight into customer charging profiles and whether time-based rates influence that behavior. In addition, the State will work with the private sector to help develop an initial charging infrastructure.

Advanced Metering Infrastructure (AMI). AMI deployments are projected to ramp up across the United States over the coming decade, with half of all households expected to be equipped with a smart meter by as early as 2015. In Connecticut, market penetration of AMI is likely to happen at a more gradual rate. The United Illuminating Company has recently upgraded its remote meter reading and billing capability and is deploying advanced meters to its customer base cost effectively. The Public Utility Regulatory Authority deferred approving Connecticut Light & Power's AMI proposal due largely to uncertainty around the technology and its benefits. As such, the impact of AMI in Connecticut is expected to be modest over the next ten years. Possible state policy options for addressing AMI-related concerns and moving forward with deployment for CL&P include an update on progress in reaching universal industry metering standards and protocols, evaluation of a specific meter technology proposal and a more phased-in implementation plan that takes into account impacts on various customer classes.

Energy Storage. While certain forms of energy storage (such as pumped hydro) have existed in the United States for nearly a century, growing concern over renewables integration has led to an increasing interest in emerging bulk and distributed storage technologies. Currently, these new technologies are typically too costly to be economically competitive with other resources, except in limited applications. However, a significant amount of federal funding has been made available to advance the state of the technology and reduce costs. Whether this will significantly change the economics over the coming decade remains uncertain. Aside from financial incentives, state level activities to promote adoption could include modifications to the regulatory framework, utility planning processes, and market rules to more fully recognize the multi-dimensional benefits that energy storage provides.

Advanced Waste-to-Energy (AWE). Connecticut is the nation's leader in converting trash to energy through the traditional incineration process. New types of AWE, such as anaerobic digestion, would achieve similar benefits with less environmental impact. As of yet, these projects are challenging in terms of commercial viability and therefore likely to proceed on a quite limited basis. Future state activities to promote development of the technology will focus on small-scale demonstration projects or other related research. For example, Connecticut's Clean Energy Finance and Investment Authority (CEFIA) is establishing a pilot program pursuant to legislation (P.A. 11-80, Section 103(b)) to test the use of anaerobic digestion on organic waste to produce electricity and heat.

Geothermal Energy. Although there is more than 3 GW of geothermal capacity in the United States, with another 800 MW scheduled to come online in the next few years, all of this capacity is located in the Western U.S. Studies have found that geothermal potential in Connecticut (and all of New England) is quite poor. Activities to promote geothermal development in Connecticut would need to focus on developing innovative drilling, power conversion, and reservoir technologies that are more effective and available at much lower costs. Such research already is happening to a limited degree in Connecticut through DOE grants.

Microgrids. While the State, to date, has taken a gradual regulatory approach to the deployment of smart grid technology, the two storms of 2011 revealed vulnerabilities in the state's current electricity system that must be addressed in planning for the state's electric future. The ability to ensure the operation of critical infrastructure during an emergency with a strategic deployment of clean distributed resources that can be isolated from the larger grid in the case of outages would require the use of smart-grid technologies. While recognizing the financial, regulatory, and operational challenges of using distributed generation (DG) resources within micro-grids to increase the resiliency of our electric infrastructure, the potential opportunity to significantly alleviate the pain, disruption, and economic loss caused by prolonged power outages warrants an analysis to evaluate and develop a targeted deployment strategy for micro-grids. To that end, DEEP will continue to investigate the deployment and funding of smart grid technology to support micro-grids as a part of a larger overall strategy on resiliency.

Conclusion: Emerging Technologies

Pursuant to Governor Malloy's Two Storm Panel Review and ongoing efforts for Connecticut to address storm disaster preparedness and recovery, DEEP will undertake a pilot program for the deployment and funding of distributed generation and microgrids, combined with smart grid technology at critical facilities (such as hospitals, prisons, and sewage treatment plants) and in city centers, as well as the use of energy improvement districts as a mechanism to support microgrids.

F. Other Issues

Although the IRP identified no likely resource need in the near-term, DEEP will continue to monitor resource supplies, including the retirement of existing generation, the effect of energy efficiency on electricity demand, and the progress of the NEEWS transmission project. DEEP will also work with ISO-NE to ensure that its market structures provide proper incentives to retain and develop new resources when and where needed. DEEP will work with ISO-NE to maintain reliability during winter cold snaps, when natural gas availability for generation is lowest.

VII. CONCLUSION

The 2012 Integrated Resource Plan (IRP) for Connecticut presents a comprehensive plan for improving Connecticut's electric energy future. The analysis performed for the IRP supports this plan, which includes a sustained commitment to expanded energy efficiency, further analysis of Renewable Portfolio Standard issues, careful monitoring of resource supplies, deployment of microgrids through a pilot program, and other steps outlined above. This plan will help Connecticut customers reduce the volume of consumption and, thus, save money when market-wide cost factors pressure rates; facilitate the development of low-cost, clean energy resources that are economic but may face barriers to implementation; find cost-effective ways to meet the clean energy objectives of the renewable targets; and support in-state jobs.